Greenhouse Gas Reduction Strategies in Utah:

An Economic and Policy Analysis

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The U.S. Environmental Protection Agency

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Greenhouse Gas Reduction Strategies in Utah: An Economic and Policy Analysis

Executive Summary

I. Background

In 1996, the Utah Office of Energy and Resource Planning (OERP) and the Utah Division of Air Quality (DAQ) obtained a grant from the U.S. Environmental Protection Agency (EPA) to conduct research on Utah's contribution to so-called Greenhouse Gas (GHG) emissions as well as the economics of mitigating these emissions.

Phase I of the research -- conducted by DAQ -- quantified and established an inventory of the State's past and future GHG emissions for the period between 1990 and 2010. The results of Phase I were published in a report entitled the *Utah Greenhouse Gas Inventory* in1997. This baseline cleared the way for OERP to begin Phase II of the research. Specifically, the objectives of Phase II were fourfold:

- Refining the greenhouse gas inventory established in Phase I.
- Identifying various GHG mitigation strategies.
- Determining the GHG reduction potential (quantity in tons CO_2) and cost of various mitigation strategies.
- Assessing the economic impact of select mitigation strategies.

Table 1. Fossil Fuel GHG Emissions Baseline in Tons CO_2, 1990-2010

Year	Residential	Commercial	Industrial	Transportation	Total
1990	7,755,745	7,773,822	15,257,954	11,695,827	42,483,347
1995	8,545,967	8,928,542	16,897,188	14,373,119	48,744,816
2000	10,009,415	10,833,816	19,158,121	16,672,343	56,673,694
2005	10,762,533	12,352,875	21,095,392	18,437,497	62,648,298
2010	11,573,856	14,092,028	23,289,703	20,410,929	69,366,516

II. Major Findings

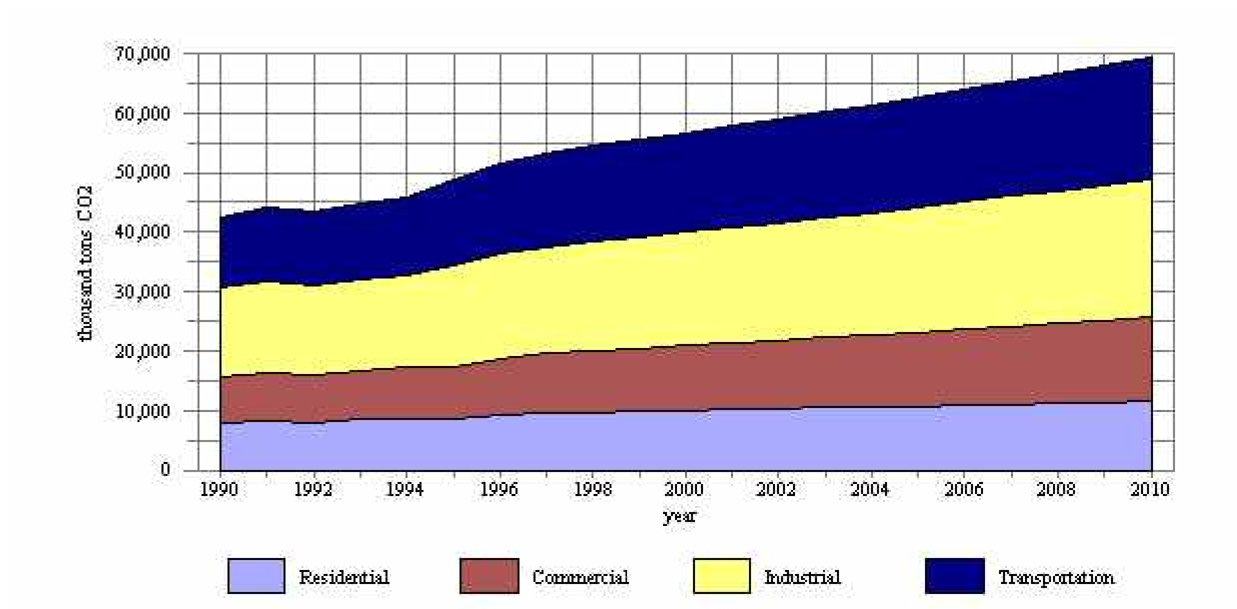
This executive summary outlines the major findings of Phase II. The following discussion is divided into three sections that cover the following topics: 1) the fossil fuel emissions baseline, 2) mitigation strategies, and 3) economic impact.

A. Baseline

Approximately 85 percent of Utah's total GHG emissions result from the consumption of fossil fuels. Throughout Phase II, energy consumption and related GHG emissions are measured at the end use or final point of consumption. As shown in Table 1 and Figure 1, fossil fuel-related GHG emissions have increased dramatically in Utah since 1990 due to rapid population growth and a strong economy. This trend will likely continue throughout the next decade with fossil fuel-related GHG emissions reaching over 69 million tons CO_2 by 2010, an increase of 63.3 percent over the 1990 level. In 1999, the industrial sector was responsible for the largest portion (33.8 percent) of Utah GHG emissions, followed by the transportation sector (29.4 percent), the commercial sector (19.0 percent), and the residential sector (17.8 percent). The transportation and commercial sectors are projected to represent increasing shares of fossil fuel-related GHG emissions.

Non-fossil fuel sources contribute the remaining 15 percent of Utah's total GHG emissions. Non-fossil fuel emissions are discussed in a separate chapter within the report.

Figure 1. Fossil Fuel GHG Emissions Baseline 1990-2010



B. Mitigation Strategies

Table 2 summarizes key information regarding the GHG emissions mitigation strategies by sector. Table 3 ranks individual fossil fuel mitigation strategies by annualized cost. This information is illustrated in Figures 2 and 3, which provide cumulative supply curves of GHG emissions reduction by cost. In each figure, various mitigation strategies fall at points along the curve based upon their annualized project cost per ton for feasible (Figure 2) and potential (Figure 3) levels of emissions reduction in 2010.

The largest, feasible emissions reductions are anticipated in the transportation sector (1,728 thousand tons), followed by the commercial sector (458 thousand tons), the industrial sector (340 thousand tons), and the residential sector (209 thousand tons). On average, mitigation costs per ton are higher for transportation sector strategies and lower for industrial and commercial sector strategies.

Table 2. GHG Cost and Reduction – Summary by Sector.

Sector Strategies	Quantity Feasible (thousand tons CO_2)	Quantity Potential (thousand tons CO_2)	Cost per ton Feasible	Cost per ton Potential
Residential	209	1,043	$72.69	$37.57
Commercial	458	2,498	$60.80	$26.53
Industrial	340	646	$49.20	$46.94
Transportation	1,728	3,161	$150.61	$97.77
Total	**2,735**	**7,348**	**$83.33**	**$52.20**

Table 3. Fossil Fuel Mitigation Strategies Ranked By Feasible $/ton

Sector	Strategy	Quantity Feasible	Quantity Potential	$/ton Feasible	$/ton Potential
Commercial	Plug Load	24,107	72,321	$2.16	$1.94
Commercial	Bldg commissioning/Recommissioning	97,508	731,310	$2.55	$1.28
Residential	Weatherization (Elec and natgas)	55,392	387,744	$4.36	$3.05
Industrial	Lighting	59,415	94,074	$6.13	$5.52
Transportation	Smart Traffic Lights and Highways	48,027	96,055	$6.62	$6.62
Industrial	Steam System Optimization (h and process h)	82,881	165,761	$12.79	$11.51
Commercial	Variable-speed drive motors	24,620	172,338	$14.27	$10.70
Residential	Lighting	28,772	230,173	$16.23	$12.17
Transportation	Tire inflation	48,027	120,068	$18.87	$18.87
Commercial	Lighting	141,871	898,519	$20.30	$15.22
Residential	Green Power Pricing/Marketing (Wind)	62,008	124,016	$20.75	$18.45
Commercial	Lighting Controls	37,832	283,743	$23.68	$16.91
Industrial	Motors (HVAC)	81,696	155,223	$25.90	$23.31
Residential	Gas water heater conversion	9,599	63,992	$30.44	$20.29
Residential	Premium Refrigerators	9,363	149,811	$44.64	$44.64
Commercial	HVAC	25,186	125,929	$45.38	$34.91
Industrial	Net Metering	82,521	165,043	$47.81	$47.81
Transportation	Convert vehicles to natural gas	57,257	95,429	$87.86	$87.86
Transportation	Enhanced I&M inspection	48,027	120,068	$94.37	$94.37
Transportation	Telecommuting	35,848	59,746	$107.79	$107.79
Transportation	Rideshare	22,405	44,809	$160.68	$80.34
Transportation	Parking Fees	37,341	74,682	$173.11	$173.11
Commercial	Green Power Pricing/Marketing (Wind)	49,240	98,479	$173.15	$136.81
Commercial	Net Metering	57,446	114,892	$191.26	$191.26
Transportation	Buy out old cars	96,055	240,137	$223.07	$223.07
Transportation	Convert vehicles to LPG	16,270	32,540	$274.86	$274.86
Industrial	Green Power Pricing/Marketing (Wind)	33,009	66,017	$279.31	$220.69
Residential	Net Metering	43,406	86,811	$286.89	$286.89
Transportation	Light Rail Doubled	68,000	160,000	NA	NA
Transportation	Buses Doubled	45,000	45,000	NA	NA
Transportation	Jet Engine Efficiency	28,519	85,557	NA	NA
Transportation	Light Rail	34,000	80,000	NA	NA
Transportation	Heavy-duty Trucks	97,634	146,451	NA	NA
Transportation	Regional (Heavy) Commuter Rail	40,000	80,000	NA	NA
Transportation	Truck-to-rail substitution	180,000	240,000	NA	NA
Transportation	Feebate for new mpg	192,109	480,273	NA	NA
Transportation	55-mph speed limit enforcement	633,961	960,547	NA	NA

Figure 2. Cost vs. Reduction Feasible

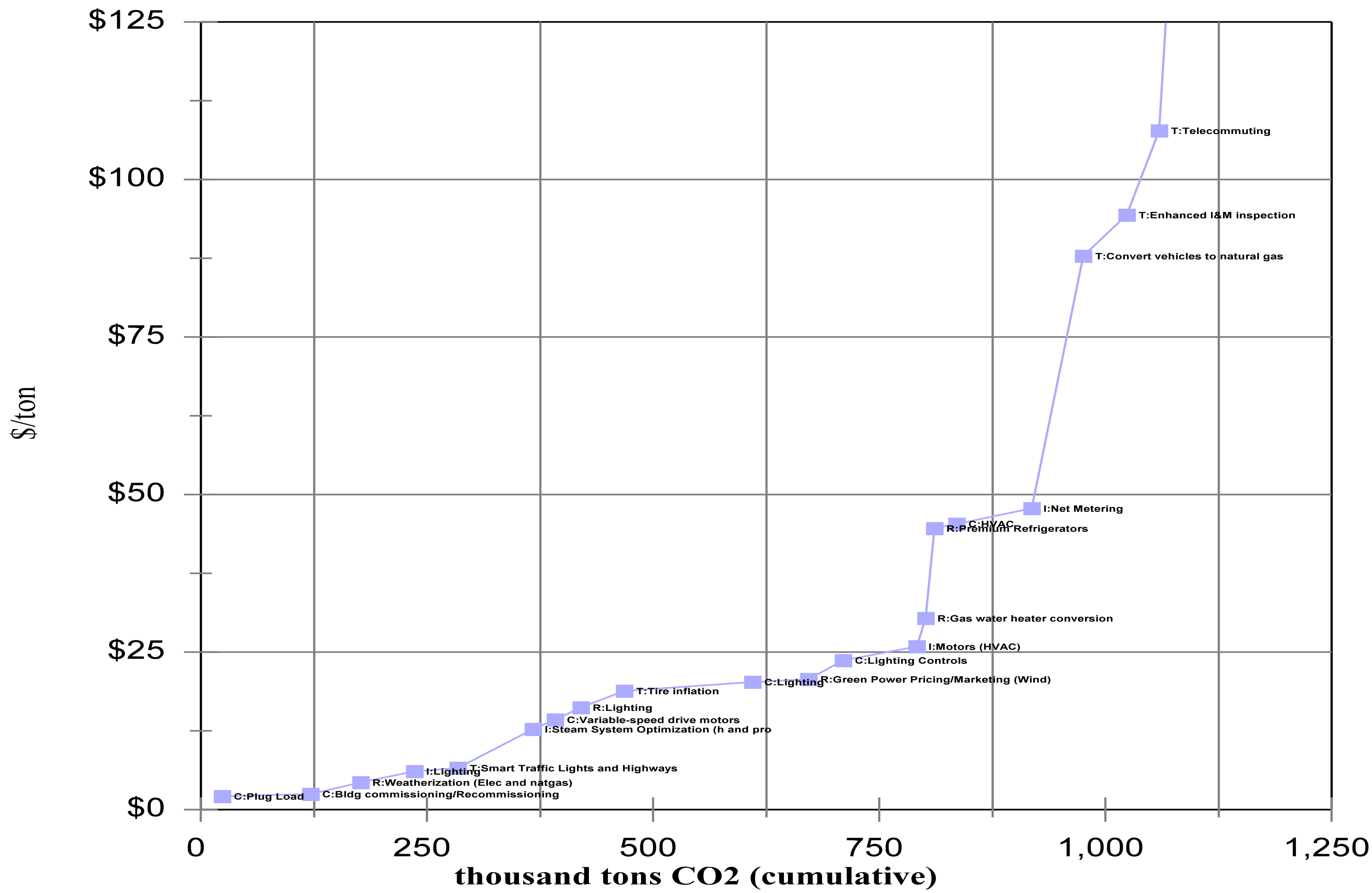
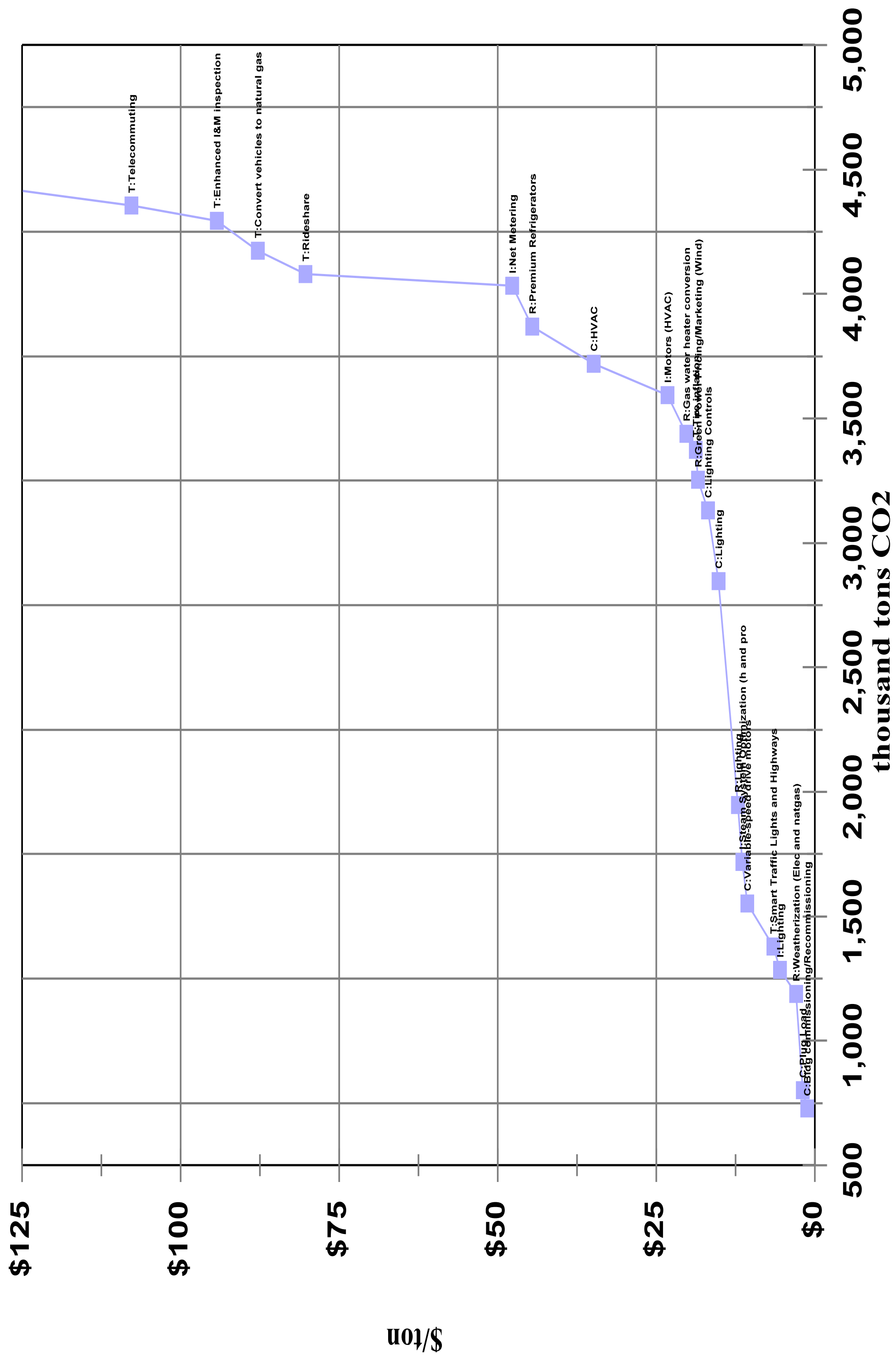


Figure 3. Cost vs. Reduction Potential



C. Economic Impact

OERP analyzed the economic impact of 13 fossil fuel-related mitigation strategies. Four strategies were considered for the residential sector, six strategies were considered for the commercial sector, and three strategies were considered for the industrial sector. OERP estimates that these strategies could reduce Utah GHG emissions by between 678 (feasible) and 3,530 (potential) thousand tons CO_2.

The estimated average annual changes in earnings and employment were addressed using an economic impact model. For simplicity summary results for both the feasible and potential economic impact scenarios are summarized in Table 4.

Under the feasible scenario for the selected 13 strategies, Utah average annual earnings were estimated to increase by more than $8.5 million dollars (0.03 percent), mostly due to investment in energy efficiency retrofits. Similarly, Utah average annual employment was estimated to increase by 482 jobs (0.04 percent).

With the potential scenario for the same strategies, the increase in Utah average annual earnings were dramatically higher at $24.1 million dollars (0.08 percent). Average annual employment was estimated to increase by 1,623 jobs (0.15 percent).

Table 4. Estimated Average Annual Changes in Earnings and Employment

Economic Impact Scenario	Change in Earnings		Change in Employment	
	Thousand Dollars	Percent	Jobs	Percent
Feasible	$8,561	0.03%	482	0.04%
Potential	$24,058	0.08%	1,623	0.15%

Part One
Introduction

I. Background

In recent years, the scientific community has conclusively determined that the global atmosphere's concentration of greenhouse gas (GHG)[1] emissions has been rising. These gases, produced from varied sources worldwide, effectively trap heat in the Earth's atmosphere that would otherwise be released into space. The growing international scientific consensus is that sustained accumulations of these gases could directly alter the average temperature of the Earth's surface. In turn, these modified temperatures may have profound implications for global and regional climate, agricultural patterns, ecosystems, and even sea level. Though speculated that some regional economies may benefit from such changes, it remains the general contention that the net effect would likely compromise the natural environments and economies of most of the world's inhabitants.

In 1988, responding to the increasing weight of scientific findings, the World Meteorological Organization (WMO) and the United Nations Environmental Program (UNEP) established the Intergovernmental Panel on Climate Change (IPCC). The IPCC was then charged with the task of assessing the available scientific, socioeconomic, and technical information in the field of climate change. Conceding the formidable challenge in identifying the differing sources of GHG emissions, nevertheless the IPCC concluded that, "the balance of evidence suggests that there is a discernable human influence on global climate."

Reported to the UN in 1990, the IPCC's findings were adopted by the General Assembly. The IPCC report further set the stage for establishing the United Nations Framework Convention on Climate Change (UNFCCC).

On June 12th 1992, along with 154 nations, the United States signed the UNFCCC in Rio de Janeiro. The Convention established a legal framework that commits the signatories to voluntary reduction of GHG emissions or other actions, such as enhancing GHG sinks, at 1990 levels.

In October, the United States became the first industrialized nation to sign the treaty and, one year later to the month, the Clinton Administration released its Climate Change Action Plan (CCAP), which called for the Nation to reduce GHG emissions to the 1990 level by the year 2000. In brief, the CCAP entails a collection of 50 initiatives or strategies that span all sectors of the economy and concentrate on reducing GHG emissions in a cost-effective manner. Broadly, the initiatives call for cooperation between government, industry, and the public.

Anticipating these international actions on GHG mitigation and to facilitate these reductions in the United States in 1990, the U.S. Environmental Protection Agency's (EPA) Climate Change Division established the State and Local Outreach Program to assist state governments in research on policies

[1] Hereafter GHG refers to greenhouse gas; GHGs refers to greenhouse gases.

to reduce GHG emissions. In 1996, the EPA awarded a research grant to the Utah Office of Energy and Resource Planning (OERP) and the Utah Division of Air Quality (DAQ) to conduct preliminary research into the economic cost associated with measures and strategies to reduce state GHG emissions.

The momentum generated at the 1992 Rio meeting led to the December 1997 Kyoto Protocol which called for certain nations to reduce their GHG emissions, during the period between 2008 and 2012, to 5 percent below 1990 levels. According to the Protocol, the United States would be required to reduced its GHG emissions, during the same period, to 7 percent below its 1990 levels. To date, however, the United States has not ratified any treaty binding the Nation to the Kyoto Protocol.

II. Scope of Research

For this research, OERP and DAQ have identified several related goals: 1) establish an energy baseline – that details the structure and pattern of energy consumption in the Utah economy; 2) identify various GHG emissions mitigation strategies; 3) determine the GHG reduction potential (quantity in CO_2 tons) and cost of the selected GHG reduction measures; and 4) when possible, assess the economic impact of GHG reduction measures.

While about 85 percent of GHG emissions in Utah result from the consumption of fossil fuels, non-fossil fuel emissions are also significant and will be addressed as well.

III. Methodology

Before mitigation strategies could be evaluated for this research, it was necessary to establish a baseline of Utah's GHG emissions. Because most GHG emissions in Utah result from fossil fuel consumption and because non-fossil fuel emissions are difficult to estimate, this research focuses primarily upon the development of a fossil fuel emissions baseline. This baseline consists of projected CO_2 emissions at the end use -- *i.e.* final point of consumption -- by economic sector. For each year between 1990 and 2010, all emissions by source and sector are estimated and totaled. The baseline provides a yardstick by which the GHG emissions reduction potential of various mitigation strategies could be evaluated.

A given reduction strategy is first evaluated in terms of its individual capacity for eliminating GHG emissions. For each mitigation strategy pertaining to each sector, an estimate of GHG reduction capacity is calculated from engineering estimates and the economic literature. Reduction is defined according to either of two categories, "feasible" or "potential."

The feasible category describes the likely reduction expected and is based on assumptions regarding market penetration, in the case of technologies, and political or institutional acceptance in the case of laws or regulations. The potential category assumes no significant barriers to measure adoption and, therefore, represents the maximum amount of reduction possible from a given mitigation measure.

With feasible and potential reduction estimated, it is then necessary to identify the cost associated with implementing a given strategy. Cost calculations are important in determining the ultimate selection of mitigation strategies, since there is wide variation in the cost per ton among the strategies.

In this research, mitigation cost is evaluated with respect to an emissions reduction amount per year. In reality, various strategies may be initiated in different years. For the purpose of comparison in this study, however, the mitigation costs for each strategy are calculated assuming that all strategies begin in the year 2001 and achieve the same level of emissions reduction in each project year.

To ensure comparability in evaluation, the cost-per-ton values for each measure are calculated in annualized or levelized dollars at a real discount rate of 5 percent. This approach accounts for the wide variation in fixed and capital costs associated with each measure. Furthermore, the levelized cost for each measure is evaluated over the same period of estimation; that is, each measure is viewed as a project that is successively undertaken or "repeated" over a 30-year period from 2001 to 2030. This adjustment ensures that costs for all measures are spread out over a long enough period so as not to penalize measures with relatively high up-front capital costs and/or longer life-cycles. Of note, no explicit accounting is made for the likely economy of scale or diminishing returns that might be realized as more measures of a given type are introduced over the 30-year time frame. Each reduction strategy is viewed as a discrete project, the scale of which does not vary over time. As a result, the feasible cost values reported in this study represent the annualized cost over a 30-year period (from 2001 to 2030) per ton of CO_2 reduction achieved each project year.

It is vital to bear in mind that the research does not explicitly account for the externalities or presumed social benefits associated with GHG reduction. For example, sulfur dioxides, nitrogen oxides, particulates, and ozone formation are all associated with fossil fuel combustion, yet externality estimates associated with mitigating each pollutant have not been calculated. Because these estimates are problematic in calculation, the costs ultimately used are estimated according to financial methodologies and not according to strict economic theory. It should further be noted that these externalities would, all else equal, lower the net cost of reduction measures. Therefore, economic estimates may be considered conservative.

In addition to externalities, other costs have not been directly incorporated. For example, government programs to improve industrial efficiency involve costs that are not readily measured and, therefore, are not directly incorporated into the financial calculation. Finally, the analyses typically do not include time-varying changes in the cost of fuel or technological assumptions.

Finally, the research concludes with an economic impact assessment of GHG reduction investments. In particular, an input-output model is specified which determines the economic impact of multi-sector investment in a subset of the selected strategies.

IV. Report Structure

The following report summarizes the research conducted for Phase II. The report is structured as follows. Part Two provides a more detailed look into the background of climate change and the theorized greenhouse effect. It also includes a timeline and discussion of international treaties on climate change. In addition, Part Two reflects on the debate over the greenhouse effect in the international science community.

Part Three outlines the development of the Utah Greenhouse Gas Emissions Inventory and the selection of mitigation strategies. In addition, the major types of GHGs are identified and described. Finally, Part Three outlines OERP's criteria for the selection of mitigation strategies for further research.

Part Four describes the development and results of the Utah energy baseline. Following a statewide overview, Part Four details energy use and carbon dioxide emissions for the following sectors:

- Residential
- Commercial
- Industrial
- Transportation
- Electric Utility

Part Five describes various GHG emissions mitigation strategies by sector. Part Five also includes a cross-sectoral discussion on mitigation opportunities associated with land use planning.

Part Six provides a overview of non-fossil fuel sources of GHG emissions. Various non-fossil fuel sources are identified and described. In addition, Part Six identifies and evaluates mitigation strategies for these emissions.

Part Seven details the results of an economic impact analysis of a subset of the mitigation strategies discussed in Part Five. The change in average annual earnings and employment are estimated for both feasible and potential scenarios.

Part Eight concludes the report by summarizing major findings and outlining the potential roles of various parties in GHG mitigation.

Appendixes present additional information.

Part Two
The Greenhouse Effect and Global Initiatives

I. Background and State of the Science

Atmospheric conditions are described in terms of either weather or climate. Weather refers to a specific condition in the atmosphere at a given place at a set time and characterizes these varying conditions in terms such as precipitation, solar insolation, humidity, and fog. Weather may also be measured in terms of rainfall, temperature, and barometric pressure. Typically a local phenomenon, weather can affect a large area as in the case of a hurricane which spans over a larger region.

Climate, in comparison, explains average weather conditions over a period of time, usually 30 years or more. As with weather, climate patterns may be analyzed locally and regionally; however, climate is described with respect to very large regions including continents, hemispheres, or even the Earth.

Climate is less difficult to predict than weather because the latter is a highly localized phenomenon. Dramatic changes in weather conditions are not inherently significant and frequent variations are expected. A rapid change in climate, on the other hand, is startling even if it is expected, and such a change would rarely register in a decade. Because climate patterns represent averages over longer time periods and larger areas, they are easier to predict than weather patterns. Granted climatic predictions are still fraught with uncertainty, but scientists can forecast climate conditions with a much higher level of certainty than they are able to forecast weather conditions.

A. Climate and Weather in Context: A History of Climate Change

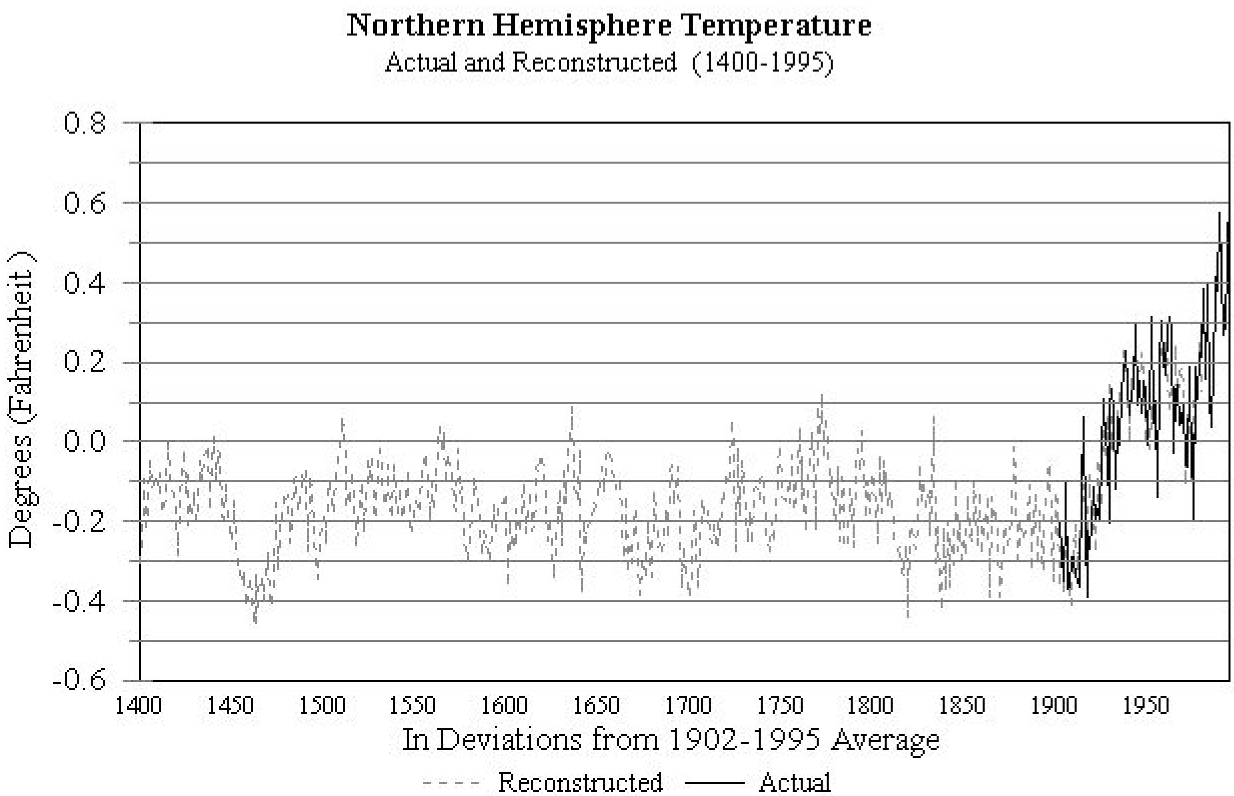
The history of the Earth's climate is as old as the planet itself. Yet the passage of time has blurred our vision of this history, providing us with few facts upon which to base conclusions about trends in climate change. Today, trends in climate are inferred from analyzing weather data produced from instrument measurements, such as thermometers, barometers, or weather balloons. Such data is critical for understanding modern climate conditions. Regrettably, however, these records only exist for a tiny fraction of the Earth's history.

It is difficult, if not impossible, to understand our modern climate by relying solely on data provided by modern record keeping on climatic indicators. Indeed, the past holds the key to a better understanding of climate phenomenon. Earlier climatic trends can be inferred "by the study of natural phenomena which are climate-dependent, and which incorporate into their structure a measure of this dependency" (Bradley, 1985)]. Such inferences provide a *proxy record* which serves as the foundation of paleoclimatology, or the study of climate predating instrumental measurements. In providing an historical context, proxy data serves as a lens through which to view the Earth's modern climate.

Proxy data includes inferences from flora, fauna, tree rings, ice cores, and coral. Though such data capture elements of climate as far back as several millennia, the relatively small number of locations measured does not yet allow scientists to build a complete picture of the global climate. Clearly, the further one reaches back in time, the less reliable and detailed the data sample becomes.

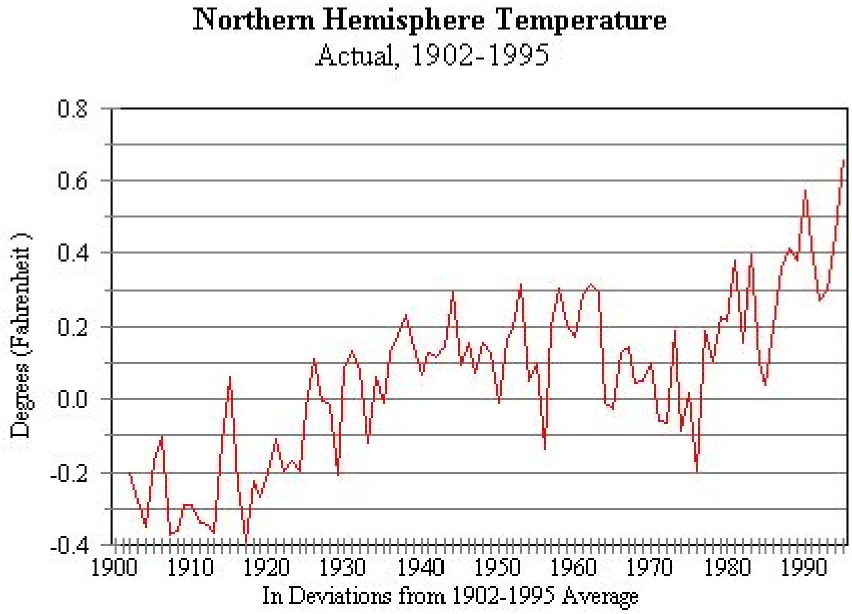
It is possible, though, to construct a proxy data set of the world's climate for the past several centuries which allows for a meaningful comparison of climate before and after the industrial revolution. This is important since a growing consensus among scientists studying global warming is that events following the industrial revolution, specifically increases in atmospheric greenhouse gas resulting from human behavior, have contributed to global warming. By comparing the climates before and after the industrial revolution, scientists are better able to speculate on the link between human behavior and changes in climate in the post-industrial era. In addition, a picture of the world's climate spanning the past several centuries also allows observers to mark the natural degree of the climate's variability.

Figure 2-1.



Perhaps the most complete set of climate data for the past several centuries is the reconstruction of the Northern Hemisphere by Mann, Bradley, and Hughes (1998). This data accounts for six centuries of proxy data based on a wide range of natural phenomenon. In compiling various samples from many points in the Northern Hemisphere, these researchers have minimized the potential limitations of any one proxy indicator while simultaneously reducing the possibility of human error. Though somewhat limited in its focus on the Northern Hemisphere, the data provides a reputable documentation of climate affecting a wide range of sites. For the purpose of this report, this proxy record is the best available source on global climate.

Figure 2-2.



The reconstruction shows the variability of climate (see Figure 2-1) and highlights several important trends such as the relative extremes in temperature. The mid-fifteenth century, for example, is the coolest period during the time series, a period commonly known as "the Little Ice Age." As shown in Figure 2-1, the twentieth century is the warmest period: nine of the warmest years in this time series (through 1997) have occurred in the past 11 years. One also notes that periods within the seventeenth and nineteenth centuries were substantially warmer than the cool periods within the sixteenth and eighteenth centuries. Mann, Bradley, and Hughes note the warming of the current century by comparing the mean temperature of this century to the temperatures of those in previous centuries. Strikingly, temperatures in previous years tend to fall well below the mean of the current century. It is important to note, however, that unusual weather patterns do not *in themselves* confirm the hypothesis of human-induced warming. However, this proxy record does provide evidence of the Earth's warming, which is not a matter of dispute among scientists. (Mahlman, 1997).

B. The Science of the Greenhouse Effect

An important factor influencing climate conditions is the atmosphere's ability to trap sunlight once it has passed through the Earth's atmosphere. Sunlight is shortwave radiation that travels through the Earth's atmosphere with little resistance. As sunlight reaches the Earth's surface, the sunlight is absorbed by the Earth. Upon return to the atmosphere, however, sunlight is transformed into thermal or long-wave radiation.

This transformation is significant because greenhouse gases in the atmosphere do not allow all of the longwave radiation to pass through the atmosphere. The longwave radiation that does not pass through the atmosphere is retained, at least temporarily, in the atmosphere; the remainder that is able to pass though the atmosphere continues to move out into space.

This process of transforming shortwave radiation into long-wave radiation and then retaining a portion of this radiation is commonly known as the *greenhouse effect*. Some scientists estimate that without this simple process the Earth's surface would be approximately 55 F cooler than it is today. Greenhouse gases that occur naturally in the atmosphere include water vapor (H_2O), carbon dioxide (CO_2), methane (CH_4), nitrous oxide (NO_2), and ozone (O_3). Some human-made compounds are also greenhouse gases, including chlorofluorocarbons (CFCs) and partially halogenated fluorocarbons (HCFCs), hydrofluorocarbons (HFCs), and other compounds such as perfluorinated carbons (PFCs). Under current conditions the greenhouse effect is critical to supporting life as we know it; a substantial shift in the equilibrium conditions underlying the greenhouse effect due to increasing anthropogenic emissions of GHGs could potentially have a detrimental effect on life as we know it.

II. International Treaties

A. Framework Convention on Climate Change

Held in Rio de Janeiro in 1992, the Framework Convention on Climate Change produced a document stipulating that 155 signatory nations stabilize anthropogenic GHG emissions to prevent dangerous interference with the climate system. Neither exact levels were set nor reduction targets made binding at the meeting.

The United States ratified the UNFCCC in 1992 and, by September 1999, another 180 countries ratified the framework. While exact limits were not set, Article 4 provided guidelines for emission reduction commitments. The United States, for example, had assumed the non-binding commitment to reduce its net GHG emissions to 1990 levels by the year 2000.

B. Kyoto Protocol

In early December 1997, over 160 nations assembled in Kyoto, Japan, to develop binding limits on GHG emissions. After 10 days of negotiations, an agreement was reached that, if ratified, would require the world's developed nations and nations with economies in transition (collectively referred to as Annex I parties) to reduce their combined annual average GHG emission levels to 5 percent below 1990 levels between 2008 and 2012. The United States agreed to reduce emissions to 7 percent below 1990 levels.

Under Article 6, Joint Implementation projects include those between Annex I parties. Projects between Annex I parties and developing countries are covered under Article 12, known as the Clean Development Mechanism (CDM). Under CDM, for example, U.S. companies could invest in clean technologies or develop forestry and sequestration projects abroad and receive credit for emissions reductions.

Although the United States placed considerable pressure on developing nations to agree to an emissions cut of their own, the effort was unsuccessful. Developing nations believe that limits on GHG emissions would pose unacceptable constraints on their economic growth and development. Nations such as China and India are determined to first raise their standard of living before agreeing to any reductions. They believe that as the leading producers of GHGs, the United States, Europe, Japan and the other developed countries should be the first to make reductions.

Before the accord will have any relevance for the United States, however, it must be ratified by the Senate. Many senators and business leaders have expressed strong distaste for the accord since the refusal of developing nations to agree on emissions reductions would force the United States and other developed countries to shoulder the burden of emissions reductions in the near future, which could have significant economic implications. In the face of significant opposition to the Kyoto treaty in the Senate, the Clinton administration may not even submit the treaty for ratification before 2000. As a result, although the United States has already implemented a national Climate Change Action Plan, it may be several years before the United States begins to implement a national plan for meeting the emission reduction targets specified under the Kyoto Protocol. (Hanscom and Jancart, 1997).

During November of 1998 delegates from 150 nations reconvened to negotiate strategies for fighting global warming. The U.S. representatives arrived under a cloud of scrutiny from critics of Clinton's support of the Kyoto Treaty in the Senate and from U.S. businesses (Krix, 1998). Prior to the negotiations the Senate unanimously passed S. Res. 98, which states that the United States should not sign an agreement that fails to include provisions ensuring that developing countries undertake, limit, or reduce GHG emissions for developing country parties within the same compliance period. To the surprise of many, the American delegation–under the direction of Undersecretary of State Stuart E. Eizenstat–further upset the president's critics by signing the 1997 Kyoto Treaty. Though largely a symbolic gesture (since the Senate must ratify the treaty before it goes into effect), the signing did heighten the conflict between the Senate and the White House and fueled the momentum for action ignited in Kyoto.

Senator Frank Murkowski (R-Alaska), Chairman of the Natural Resource Committee said:

> "The president made two grave errors in signing the treaty. First, he undercut the leverage of his own negotiators currently meeting in Buenos Aires. Second, he defied the bipartisan views of the Senate which unanimously voted in support of a resolution explicitly asking the president not to negotiate or sign a treaty that did not include the full participation. Thus, he probably doomed this treaty." (Fizanz, 1998b).

Though it remains to be seen what should come of the treaty, the president certainly faces serious opposition to ratification in the Senate.

In spite of the criticisms leveled by his critics, President Clinton's stand at Buenos Aires will be remembered as somewhat of a breakthrough. Undersecretary Eizenstat made real gains in persuading other nations to accept the administration's approach to addressing global warming. The president's market-based approach to climate change, originally viewed with skepticism in Kyoto, was embraced by a handful of developing nations in Buenos Aires. This approach consists of three elements: 1) joint implementation under Article 6; 2) the Clean Development Mechanism under Article 12; and 3) international trading under Article 17.

Arguably, the most significant breakthrough of the proceedings came in the final hours of the talks as two developing nations (Argentina and Kazakhstan) agreed to adopt voluntary limits on their own emissions. This step moved beyond the agreement secured in the Kyoto Treaty and may be viewed as a direct challenge to the block of developing nations still refusing to adopt emissions limits. As a result, it is reported that more than a dozen countries are considering the adoption of similar limits.

Most commentators credit the financial incentives built into the Kyoto Mechanisms as partly responsible for the recent adoption of such limits.

III. The International Science Community

There is no dispute among climatologists, meteorologists, paleoclimatologists, and other scientists in related fields that the Earth's climate is indeed warming. Furthermore, there is a general consensus that human activity plays a role, albeit unclearly defined, in promoting the increase in GHGs (particularly CO_2, methane, and nitrous oxide which all occur naturally). The claim that GHG levels have a strong relation to temperature and climate is generally accepted as well.

Since 1800, CO_2 atmospheric concentrations have increased by 25 percent, methane concentrations have more than doubled, and nitrous oxide concentrations have risen by approximately 80 percent (Division of Air Quality, 1996). CFCs also contribute to GHG formation. Between the 1950s until the mid-1980s, when international concern over CFCs grew, the use of these gases increased nearly 10 percent per year. Consumption of CFCs is declining quickly as these gases are phased out under the "Montreal Protocol of Substances that Deplete the Ozone Layer." Use of CFC substitutes that contribute to global warming, to a lesser extent, is expected to grow substantially.

The United Nations and the World Meteorological Organization established the Intergovernmental Panel on Climate Change (IPCC) in hopes of creating an authoritative voice to explain climate change and its implications. While some disagree with all or parts of the IPCC's findings, the research is embraced by U.S. scientists and government agencies supporting the United States Climate Program.

Part Three
Utah Greenhouse Gas Emissions Inventory and Mitigation Strategies

I. Phase I: The Utah Greenhouse Gas Inventory

To effectively develop policies to reduce GHG emissions, a state must first identify its anthropogenic emissions and estimate the contribution of these emission sources to overall radiative forcing. The State of Utah's Phase I report, *(The Utah Greenhouse Gas Inventory, 1996),* provides a detailed accounting of GHG production in Utah during 1990 and 1993. Numerous GHGs are emitted in Utah, the most common being carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (NO_2). Both inventories outline a rudimentary historical baseline of Utah's GHG production with emissions measured by translating the volume of particular gas into its corresponding CO_2 equivalent. That is, for each ton of gas released into the atmosphere, the amount of CO_2 with the equivalent heat-trapping effect is computed. By using these standard CO_2-equivalent units, emissions of various gases may be compared and added.

The inventory revealed a previously unknown fact: Utahns produce almost twice as much GHG per capita as the national average. Utah emissions in 1993 (72 million tons CO_2 equivalent) accounted for more than 1.2 percent of total U.S. emissions, while Utah represents only 0.7 percent of the country's population. This means Utah produced 1.7 times more CO_2 equivalent per person than did the average U.S. state.

A. Carbon Dioxide

The primary source of Utah's GHG emissions is not excessive motor fuel consumption as might be expected but, rather, CO_2 from coal burning for the production of electricity. Each year Utah's five major power plants burn nearly 13 million tons of coal. In 1993, the electric utility sector alone accounted for nearly 50 percent of Utah's GHG emissions, dwarfing both the transportation and industrial sector emissions.

In contrast, many states have a blend of electric generating capacity, including hydropower, nuclear power, and other low CO_2-emitting generation in addition to coal-fired steam generation. In California, for example, emissions from power generation account for less than 10 percent of the state's CO_2 emissions. (It should be noted that California imports a great deal of coal-fired electricity from Utah, yet the associated CO_2 emissions appear on Utah's inventory.)

Utah's second leading source of GHGs is the transportation sector. Motor fuel combustion for transportation released nearly 13 million tons of CO_2 in 1993 and accounted for 18 percent of all emissions. Fuel requirements for transportation have increased dramatically during the last several years, and CO_2 emissions have increased proportionately.

Utah's heavy industrial operations such as Geneva Steel, Kennecott Copper and several cement and lime producers consume large quantities of coal, natural gas and various petroleum products to produce process heat. Releasing 9.8 million tons of CO_2 in 1993, Utah's industrial sector contributed more than 13 percent of the state's GHGs.

Burning mostly natural gas, the residential and commercial sectors are responsible for the remainder of Utah's fossil fuel CO_2 emissions (7 percent of total emissions).

In total, fossil fuel consumption for electricity generation, transportation, industry, accounts for the vast majority (more than 85 percent) of Utah's GHG emissions.

Additional CO_2 is released by a variety of production processes, including lime production, cement production, and limestone use. Together these activities produced 1.7 million tons of CO_2 through non-energy activities.

B. Methane

The second most abundant GHG produced in Utah is methane (CH_4). In 1993, more than 400,000 tons were released into the atmosphere and accounted for approximately 12 percent of Utah's GHG emissions. (Note: In terms of heat trapping ability, methane's "global warming potential" is 21 times greater than that of CO_2).

The largest source of methane emissions in Utah is coal mining. In coal operations, methane is released prior to extraction to preclude the risk of explosion and fire. Although some is extracted and sold, venting is typically the most economically viable alternative. Approximately 213,000 tons of methane were released from underground coal mines in 1993, accounting for 6.43 percent of GHG emissions.

Methane is also released during oil and gas production, as well as during oil refining. A by-product of these operations, methane is often vented or flared. In addition, some is unintentionally leaked from oil and gas distribution systems during transport. Although difficult to assess, methane emissions from the oil and gas sector are placed at more than 60 thousand tons. These sources represent approximately to 1.83 percent of the state's total GHG emissions.

Domesticated animal food digestion is responsible for a notable share of Utah's methane emissions. In 1993, livestock produced more than 73 thousand tons of methane, which is more than 2 percent of total GHG emissions. Dairy and beef cattle were largely responsible for this total.

Cows are not the only animals involved in Utah methane production. In the process of anaerobic decomposition, microbes transform animal and human wastes into methane. By digesting human wastewater, animal manure and the contents of landfills, microbes generated more than 63 thousand tons in 1993. Emissions from these sources amounted to just under 2 percent of Utah's total GHG emissions.

C. Nitrous Oxide

Utah also produces a third important GHG, nitrous oxide (N_2O). In 1993, approximately 450 tons of nitrous oxide were released through the use of fertilizer, a relatively small amount representing 0.17 percent of total GHG equivalent emissions.

D. Utah Forests

Forest and land-use management have important impacts on atmospheric CO_2. As they grow and develop, living trees absorb CO_2. When trees are harvested for milling or fuel use, or when they die and decompose, stored CO_2 is released back into the air. In 1993 approximately 35 thousand more tons of CO_2 were absorbed by trees than were released from trees. In effect, Utah trees absorbed about 0.05 percent of the state's GHG emissions.

II. Goal of the Utah Greenhouse Gas Mitigation Plan

The goal of Utah's Phase II is to identify a range of GHG mitigation strategies that will reduce forecasted emissions. Strategies may target reductions in certain sectors or concentrate on specific GHGs.

As evidenced by the research in Phase I, the majority of Utah's GHGs are released from the combustion of fossil fuel energy. Mitigation strategies include projects and programs designed to improve energy efficiency and reduce fossil fuel consumption.

The study analyzes strategies in seven major sectors: residential, commercial, industrial, transportation, electric utilities, non-fossil fuel sources, and land-use planning. The strategies can be divided into three major types: 1) reducing energy use through energy efficiency; 2) reducing GHG emissions through energy substitution; 3) reducing the amount of GHG emissions from CO_2 energy production.

Phase II introduces Utah policymakers to a broad range of mitigation strategies. These strategies are evaluated against several criteria, as described below. Each strategy will be examined in detail, and -- where possible – the cost per ton of CO_2 emissions reduced will be estimated. In this way, each strategy may be compared on a cost-effectiveness basis and ranked accordingly.

Once a set of strategies has been outlined, the corresponding economic impact will be assessed using an input-output model. Economic impact analysis will estimate the overall effect of GHG reduction on the Utah economy and employment levels.

Utah currently has no formal plan to develop a GHG reduction program. However, should the state choose to do so, the Phase II report may provide the foundation for future research. Phase II, then, is intended to serve as a springboard for future discussions in Utah about how to reduce GHG emissions.

III. Criteria for Selection of Mitigation Strategies

Criteria are standards for assessing alternative mitigation strategies [States Guidance Document 4-1]. Rather than a strict set of guidelines, the criteria employed in Phase II are guidelines to ensure a comprehensive and consistent consideration of relevant constraints when selecting mitigation strategies. The following are the criteria in order of priority that this report uses:

- *Amount of GHG Emissions Reduced*. Every strategy should reduce current or future GHG emissions. Strategies that fail to do so are not considered.
- *Participation Across Utah's Economic Sectors and Geographic Locations.* Different strategies will affect some sectors or locations more than others. As a matter of principle, this report tries to distribute the costs and benefits of reducing GHGs in an equitable manner. Since all sectors contribute to Utah's GHG emissions, all should share in the reduction effort.

- *Cost Efficiency.* Any attempt to reduce GHGs will entail costs. However, some strategies are less costly than others. Furthermore, some strategies lead to a return on an initial investment that ultimately recovers all or some of the up-front costs. This report gives preference to strategies that cost less relative to other strategies with similar GHG reduction potential. Private and public sector costs and savings are recognized.
- *Ancillary Benefits and Costs.* Some mitigation strategies affect other state priorities, either directly or indirectly. Various strategies produce benefits by enhancing environmental quality, social welfare, or government revenue. Costs can occur when a strategy negatively affects one of these items or other legitimate competing values. Reduced air pollution and traffic congestion are generally viewed as benefits, not costs, of GHG mitigation.
- *Political Feasibility.* Public acceptability is an important consideration of mitigation strategies. Of course, reducing GHGs is not without costs; clearly, meaningful reductions will only come with some sacrifice and effort. However, as a matter of principle, this report tries to highlight policies that will likely face less organized resistance than others. In the case that the state adopts an official plan to reduce GHG emissions, public involvement and education should be used to help gain perspective and provide additional information. Including the public may also help build public support.

In addition to the substantive criteria above, the following process-oriented criteria are also employed in the selection of mitigation strategies.

- *Measurability.* This report recognizes that strategies that are measurable in terms of cost and quantity of GHG reduction may prove to be more valuable to policy makers and the public at-large than those strategies that are not measurable. Benefits of measurablity may include more accurate forecasting of individual strategies and more value in comparing various strategies. Wherever possible the strategies are quantified both in the amount of emissions reduced and in terms of cost (EPA, 1995).

Part Four
Utah Energy Baseline

I. Overview of Utah Energy Use and Greenhouse Gas Emissions

A. Utah Energy Use by Fuel and Sector

To identify the appropriate GHG mitigation strategies for all energy-consuming sectors in the state, it is first necessary to develop a statewide energy baseline that accounts for sector-by-sector consumption by fuel use and end-use technology. This section provides an overview of Utah's baseline energy use and CO_2 emissions. Although most of the Utah energy dataset exists for the period 1960-1998, the period examined spans 1990 to 1998 to better represent more recent history and the structure of Utah's energy economy.

Across Utah's economy approximately 85 percent of Utah's total CO_2-equivalent emissions result from fossil fuel consumption.

To provide a basis of the role of these fuels in the state's economy, Table 4-1 gives the carbon and CO_2 content of coal, petroleum products, and natural gas. The measure of pounds of carbon per million Btu is known as the *carbon coefficient*. In the case of petroleum products, the carbon factor is a weighted average of several fuels. In analogous fashion, a *CO_2 factor* is reported in the right-hand column, which measures tons of CO_2 per trillion Btu. To give a sense of scale, note that 1 million Btu is not a particularly large quantity of energy, since the typical Utah household (not including transportation) uses about 165 million Btu a year. Of further note, methane and other GHG emissions are typically reported in tons of CO_2-equivalent units.

Table 4-1. Carbon Content of Fossil Fuels

	Pounds of Carbon per Million Btu	Tons of CO_2 per Trillion Btu
Coal	56.0	102,667
Petroleum Products	43.0	78,833
Natural Gas	31.9	58,483

B. Methodology

Establishing an energy baseline is somewhat problematic. A fundamental choice must be made whether to measure energy used directly for an application such as power generation ("direct accounting") or indirectly at the end use in applications such as electric motors or appliances ("end use accounting"). In the case of the former strategy, the methodology is straightforward: 1) first, for each fuel, count the physical units of consumption, such as barrels, cubic feet, or short tons; 2) convert the physical units to energy units (million Btu); 3) multiply by the carbon coefficient (which translates million Btu to carbon pounds); 4) adjust for stored and oxidized carbon; and 5) convert to tons of CO_2.

Because the "end use" methodology accounts for energy use at the final point of consumption – the last link in the energy delivery chain – all of the thermodynamic losses associated with moving energy from the point of production to the point of consumption are accounted for in end-use data. Specifically, these losses relate to the conversion of fuel to electricity, the movement of power over great distances by transmission wires, and the voltage transformations required to provide safe and

Table 4-2. Utah CO_2 Emissions by Energy Source, Excluding Electricity Exports (in thousand tons)

	Coal	Natural Gas	Motor Gasoline	Other Petroleum	Electric Sales	Electric Losses	Total
1990	5,370	7,333	6,825	6,295	5,226	11,431	42,480
1991	5,269	7,967	7,098	6,620	5,398	11,745	44,103
1992	4,736	7,282	7,306	6,637	5,622	12,008	43,592
1993	4,514	8,286	7,687	6,606	5,724	12,093	44,909
1994	4,680	7,971	7,930	6,707	6,056	12,637	45,982
1995	4,409	9,164	8,476	7,378	6,264	13,050	48,741
1996	4,435	9,524	8,639	8,195	6,739	14,024	51,554
1997	4,365	9,760	8,987	8,849	6,914	14,359	53,234
1998	4,680	9,911	9,344	8,888	7,024	14,622	54,469

reliable power to the end user. Table 4-2, which describes CO_2 emissions by energy source, includes categories for both the actual electricity supplied to the end user (sales) and the associated losses in delivering this electricity.

As apparent from Table 4-2, electricity and associated losses represent a significant share of total GHG emissions. By comparison, in the "direct accounting" methodology, the total fuel consumed would account for the thermodynamic losses as "extra" fuel consumed to make up for the energy lost in the process of delivery. Both methodologies provide comparable estimates of carbon emissions but differ in accounting approaches.

The baseline analysis in this report employs the "end use" methodology. This approach is favored because it begins with an accounting, by end-use sector, of the major uses of energy. Therefore, it is easier to target specific GHG mitigation measures to specific energy uses. The end-use sectors are the residential, commercial, industrial, and transportation sectors. In the residential sector, for example, end uses include refrigerators, water heaters, and other household appliances. For the commercial sector, primary end uses include lighting, refrigeration, and heating, ventilation, and air conditioning (HVAC). Industrial sector processes are used in manufacturing. Motor gasoline, diesel fuel, and jet fuel used by automobile, truck, air, and rail travel and freight are examples of end uses in the transportation sector.

Table 4-3. Utah CO_2 Emissions by Energy Source, Excluding Electricity Exports (as a percent)

	Coal	Natural Gas	Motor Gasoline	Other Petroleum	Electric Sales	Electric Losses	Total
1990	12.6%	17.3%	16.1%	14.8%	12.3%	26.9%	100.0%
1991	11.9%	18.1%	16.1%	15.0%	12.2%	26.6%	100.0%
1992	10.9%	16.7%	16.8%	15.2%	12.9%	27.5%	100.0%
1993	10.1%	18.5%	17.1%	14.7%	12.7%	26.9%	100.0%
1994	10.2%	17.3%	17.2%	14.6%	13.2%	27.5%	100.0%
1995	9.0%	18.8%	17.4%	15.1%	12.9%	26.8%	100.0%
1996	8.6%	18.5%	16.8%	15.9%	13.1%	27.2%	100.0%
1997	8.2%	18.3%	16.9%	16.6%	13.0%	27.0%	100.0%
1998	8.6%	18.2%	17.2%	16.3%	12.9%	26.8%	100.0%

In Utah, about 95 percent of electric power generation is coal-fired, with the remainder comprised of natural gas, light fuel oil, and hydroelectric power. In addition, Utah exports significant electricity, most of which consists of power sales to Los Angeles Department of Water and Power (LADWP).

Table 4-4. Average Annual Growth Rate in CO_2 Emissions, by Energy Source

	Coal	Natural Gas	Motor Gasoline	Other Petroleum	Electric Sale	Electric Losses	Total
1991	-1.9%	8.6%	4.0%	5.1%	3.3%	2.8%	3.8%
1992	-10.1%	-8.6%	2.9%	0.3%	4.2%	2.2%	-1.2%
1993	-4.7%	13.8%	5.2%	-0.5%	1.8%	0.7%	3.0%
1994	3.7%	-3.8%	3.2%	1.6%	5.8%	4.5%	2.4%
1995	-5.8%	14.9%	6.9%	9.9%	3.4%	3.3%	6.0%
1996	0.6%	3.9%	1.9%	11.0%	7.6%	7.5%	5.8%
1997	-1.6%	2.5%	4.0%	7.0%	2.6%	2.6%	3.2%
1998	7.2%	-0.2%	4.0%	3.9%	2.0%	2.0%	3.2%
TOTAL	**-12.9%**	**35.2%**	**36.9%**	**41.2%**	**34.4%**	**27.9%**	**28.2%**

Table 4-5. Utah CO_2 Emissions by Energy Source and End-Use Sector in 1998 (in thousand tons)

	Coal	Natural Gas	Motor Gasoline	Other Petroleum	Electric Sales	Electric Losses	Total
Residential Sector	164	3,440	0	101	1,953	4,066	9,724
Commercial Sector	332	1,877	9	269	2,522	5,251	10,281
Industrial Sector	4,185	4,416	139	1,854	2,549	5,306	18,448
Transportation Sector	0	177	9,196	6,575	0	0	16,016
All Sectors	**4,680**	**9,911**	**9,344**	**8,888**	**7,024**	**14,622**	**54,469**

Overall, CO_2 emissions from coal have declined from 5.4 to 4.7 million tons in the 1990s, a total decline of 12.8 percent, or about 1.6 percent a year. The use of coal has declined in the industrial sector but especially in the residential and commercial sectors, which use small amounts. In contrast, CO_2 emissions from natural gas have increased from 7.3 to 9.9 million tons in the decade, a total increase of 35.1 percent or about 4.4 percent a year.

Other petroleum products are distillate fuel oil, residual fuel oil, and LPG. CO_2 emissions from these

Table 4-6. Utah CO_2 Emissions by Energy Source and End-Use Sector in 1998 (as a percent)

	Coal	Natural Gas	Motor Gasoline	Other Petroleum	Electric Sales	Electric Losses	Total
Residential Sector	0.3%	6.3%	0.0%	0.2%	3.6%	7.5%	17.9%
Commercial Sector	0.6%	3.4%	0.0%	0.5%	4.6%	9.6%	18.9%
Industrial Sector	7.7%	8.1%	0.3%	3.4%	4.7%	9.7%	33.9%
Transportation Sector	0.0%	0.3%	16.9%	12.2%	0.0%	0.0%	29.4%
All Sectors	**8.6%**	**18.2%**	**17.2%**	**16.3%**	**12.9%**	**26.8%**	**100.0%**

products have increased from 6.3 to 8.9 million tons in the decade, a total increase of 41.1 percent, or about 5.1 percent a year. In this category, distillate fuel and LPG have increased while residual fuel consumption has decreased. Motor gasoline has increased from 6.8 to 9.3 million tons, a total increase of 36.9 percent, or about 4.6 percent a year. Finally, combined electricity sales and associated losses have increased from 16.7 to 21.6 million tons, a total increase of 30.0 percent, or about 3.7 percent a year.

The Utah CO_2 baseline in percentage terms is shown in Table 4-6. Note the significance of electricity losses as a percentage of total emissions. These losses alone are roughly twice the level of any fuel used directly in any application. Table 4-4 shows the year-by-year changes in emissions by source.

Table 4-7. Utah Residential Electricity Use

	Consumption (million kWh)	Households (thousands)	Household Average (kWh)
1990	4,246	564.1	7,526
1991	4,460	572.0	7,797
1992	4,505	587.8	7,664
1993	4,726	605.6	7,804
1994	5,009	623.0	8,040
1995	5,041	640.8	7,866
1996	5,481	663.7	8,259
1997	5,660	692.0	8,179
1998	5,756	76.4	8,034

C. The Matrix of Total Energy Use and CO_2 Emissions

Utah's total CO_2 emissions for 1998 are displayed by energy source and end-use sector in Table 4-5. The share of each fuel's contribution to total emissions is shown in Table 4-6.

Electricity sales and their associated losses contribute significantly to GHG emissions. Electric

Utah Population Growth

Utah's population is growing faster than that of any other state in the nation, at a rate of 2.6 percent annually compared to 1.1 percent annually nationwide. Contrary to popular belief, most of this growth is internally-generated. Population growth is made up of two components: the difference of in-migration compared with out-migration and the difference of number of births relative to number of deaths. Most of Utah's growth stems from its high birth rate, outpacing any state in the United States. Add this to a substantial amount of in-migration, and Utah growth is indeed impressive.

In terms of GHG emissions, this growth is important. By definition anthropogenic emissions come from people; population growth, therefore, results in a proportional increase in emissions, assuming that per capita emission rates are held constant. The Utah Greenhouse Inventory reveals a previously unknown fact: Utahns produce almost twice as much greenhouse gas per capita as the national average. Utah emissions in 1993 (72 million tons of CO_2 equivalent) accounted for more than 1.2 percent of total U.S. emissions, while Utah represents only 0.7 percent of the U.S. population. This means Utah produced 1.7 times more CO_2 equivalent per person than did the average U.S. state.

These two factors, a growing population and a high per capita emission rate, lead to tremendous growth in GHG emissions. Any emissions goal that is tied to a benchmark set to a point of time will likely pose serious challenges to Utah.

losses are approximately 2.08 times the amount of electric sales. Combined electricity sales and losses represent about 39.7 percent of total CO_2 emissions. Petroleum products account for 33.5 percent and dominant the transportation sector. Natural gas contributes 18.2 percent, while coal represents 8.6 percent. Again, it is important to emphasize that in Utah about 95 percent of electricity is coal-fired. If the CO_2 accounting had started with the fuel input at electric power plants, and not considered end-use electricity, then coal would have been the largest source. One should, therefore, appropriately interpret the electricity sales and losses as 95 percent coal in origin.

II. Utah Residential Sector and Carbon Dioxide Emissions

A. Overview of Aggregate Trends

In Utah's residential sector, electricity and natural gas are the two primary energy sources. Through the 1990s, both residential electricity and natural gas use have increased, generally tracking the state's rapid growth in population. According to Table 4-7, between 1990 and 1998, residential electricity consumption increased from 4.2 to 5.8 billion kilowatthours (kWh), a 36.0 percent increase overall. Natural gas demand (see Table 4-8) increased from 43.4 to 56.8 billion cubic feet (bcf), a 30.9 percent increase overall. For electricity, this trend represents an annual average growth rate of 4.4 percent in the current decade. Natural gas has increased less rapidly with an annual average growth rate of 3.9 percent.

Table 4-8 Utah Residential Natural Gas Use

	Consumption (mmcf)	Customers (thousands)	Customer Average (mcf)
1990	43,424	453.0	95.9
1991	50,572	455.6	111.0
1992	44,701	467.7	95.6
1993	51,779	484.4	106.9
1994	48,922	503.6	97.1
1995	48,975	523.6	93.5
1996	54,344	562.3	96.6
1997	58,108	567.8	102.3
1998	56,843	588.4	96.6

Total energy use is often disguised by the growth in overall population. For the residential sector, a better indication of the growth in energy use is given by the change in average household energy use. Electricity demand hasgenerally increased in Utah when evaluated in terms of average household use. Beginning the decade at about 7,500 kWh, the most recent average is now about 8,000 kWh. Both total and average residential electricity demands are shown in Table 4-7.

For natural gas, the growth pattern in energy use is more erratic. Overall residential natural gas use has been growing with population, but average household use has remained roughly constant. Both total and average natural gas demands are shown in Table 4-8. In Utah, natural gas is the primary winter heating fuel and its use is weather-dependent. While unusually cold winters spike natural gas demand, mild winters result in low or moderate natural gas use. The average household natural gas consumption has tracked between 93 mcf and 111 mcf.

Household average consumption may be readily compared to the average electricity consumption for all U.S. households. In the 1990s, the national average household electricity consumption was approximately 23 to 28 percent higher than Utah's. During this period, the national average residential electricity consumption per household has held at over 10,000 kWh per household each year. For natural gas, the United States average household use in the 1990s was about 90 mcf per year.

Overall, through the 1990s, residential electricity use in Utah increased in total and for the average household, while natural gas increased in total but remained roughly constant for the average household. These facts provide a benchmark for policy makers as they consider various GHG emissions mitigation options across sectors.

B. Baseline Carbon Dioxide Emissions in the 1990s

Tables 4-9 and 4-10 present Utah residential sector energy-related CO_2 emissions by fuel. As Table 4-9 reveals, natural gas consumption accounts for approximately one-third of the sector's total CO_2 emissions with the remainder accounted for by electricity sales and losses. All other fuels, such as coal, LPG, and heating oil have declined from 5.3 percent of total residential sector CO_2 emissions at the beginning of the decade to about 3.0 percent by 1998. Electricity losses represent over twice the amount of electricity sales. As a result, reducing electricity use is an important way to eliminate or slow CO_2 emissions. For example, if residential sector electricity demand is reduced by one quarter and results in a reduction of about 0.5 million tons CO_2, then the CO_2 emissions from accompanying electricity losses are reduced by over 1.0 million tons. The total reduction is over 1.5 million tons CO_2.

Table 4-9. Utah Residential CO_2 Emissions (thousand tons)

	Natural Gas	Electric Sales	Electric Losses	All Other Fuels	Total
1990	2,751	1,441	3,151	412	7,756
1991	3,158	1,513	3,295	397	8,364
1992	2,805	1,529	3,266	365	7,964
1993	3,257	1,604	3,388	291	8,539
1994	3,042	1,700	3,547	198	8,487
1995	3,031	1,710	3,563	241	8,546
1996	3,297	1,860	3,871	293	9,321
1997	3,524	1,921	3,989	226	9,661
1998	3,440	1,953	4,066	265	9,724

Table 4-10. Utah Residential CO_2 Emissions (as a percent)

	Natural Gas	Electric Sales	Electric Losses	All Other Fuels	Total
1990	35.5%	18.6%	40.6%	5.3%	100.0%
1991	37.8%	18.1%	39.4%	4.7%	100.0%
1992	35.2%	19.2%	41.0%	4.6%	100.0%
1993	38.1%	18.8%	39.7%	3.4%	100.0%
1994	35.8%	20.0%	41.8%	2.3%	100.0%
1995	35.5%	20.0%	41.7%	2.8%	100.0%
1996	35.4%	20.0%	41.5%	3.1%	100.0%
1997	36.5%	19.9%	41.3%	2.3%	100.0%
1998	35.4%	20.1%	41.8%	2.7%	100.0%

The annual growth of CO_2 emissions in the Utah residential sector is shown in Table 4-11. While growing with population overall, natural gas use has fluctuated annually due to the variation in weather patterns. Electricity demand, in contrast, has consistently outpaced population growth in recent years. All other fuels, primarily coal and LPG, have been generally declining this decade. The combined annual average growth rate of CO_2

Table 4-11. Annual Growth in Utah Residential CO_2 Emissions

	Natural Gas	Electric Sales	Electric Losses	All Other Fuels	Total
1991	14.8%	5.0%	4.5%	-3.7%	7.8%
1992	-11.2%	1.0%	-0.9%	-8.1%	-4.8%
1993	16.1%	4.9%	3.8%	-20.2%	7.2%
1994	-6.6%	6.0%	4.7%	-31.9%	-0.6%
1995	-0.4%	0.6%	0.5%	21.8%	0.7%
1996	8.8%	8.7%	8.6%	21.5%	9.1%
1997	6.9%	3.3%	3.3%	-22.7%	3.6%
1998	-2.4%	1.7%	1.9%	17.1%	0.7%
TOTAL	**25.0%**	**35.6%**	**29.0%**	**-35.8%**	**25.4%**

emissions from electricity sales and losses, which have been at 3.9 percent this decade, suggests again that reducing residential electricity use is a key GHG mitigation strategy.

C. The Matrix of Residential Sector Energy by End Use

To better understand how energy is used in the residential sector, and the resulting CO_2 emissions, a matrix of energy sources including electricity losses and end uses is presented in Tables 4-12 and 4-13. As evident, the major fuels are electricity and natural gas with minor contributions from fuel oil and LPG. Highlighting end use by fuel, the table illustrates those areas which should be targeted with mitigation measures to provide the most meaningful GHG reductions.

By fuel, electric sales and associated losses account for about 62 percent of total Utah residential sector CO_2 emissions. Natural gas, which has a significantly lower carbon-to-Btu ratio than coal, contributes over a third of total CO_2 emissions. By end use, as indicated in Table 4-13, roughly half of all CO_2 emissions are accounted for by space and water heating. Combined, refrigeration and

Table 4-12. Utah Residential CO_2 Emissions in 1998 (in thousand tons)

	Electricity	Electric Losses	Natural Gas	All Other Fuels	Total
Space heating	211	439	2,133	242	3,025
Secondary heating	10	20	0	0	30
Central air conditioning	137	285	0	0	421
Room air conditioning	113	236	0	0	349
Water heating	252	524	1,170	4	1,950
Refrigerators	295	614	0	0	909
Lighting	227	472	0	0	698
Clothes washer	174	362	0	0	536
Range/oven	64	134	69	21	288
Clothes dryer	117	244	69	0	430
All other appliances	354	736	0	0	1,089
Total	**1,953**	**4,066**	**3,440**	**266**	**9,724**

Table 4-13. Utah Residential CO_2 Emissions in 1998 (as a percent)

	Electricity	Electric Losses	Natural Gas	All Other Fuels	Total
Space heating	2.2%	4.6%	21.9%	2.5%	31.1%
Secondary heating	0.1%	0.2%			0.3%
Central air conditioning	1.4%	2.9%			4.3%
Room air conditioning	1.2%	2.4%			3.6%
Water heating	2.6%	5.4%	12.0%		20.1%
Refrigerators	3.0%	6.3%			9.3%
Lighting	2.3%	4.9%			7.2%
Clothes washers	1.8%	3.7%			5.5%
Range/ovens	0.7%	1.4%	0.7%	0.2%	3.0%
Clothes dryers	1.2%	2.5%	0.7%		4.4%
All other appliances	3.6%	7.6%			11.2%
Total	**20.1%**	**41.8%**	**35.4%**	**2.7%**	**100.0%**

lighting represent nearly 17 percent of all emissions. The balance is comprised mainly of clothes washing and drying, and climate control (HVAC).

III. Utah Commercial Sector Energy Use and Carbon Dioxide Emissions

A. Overview of Aggregate Trends

As with the residential sector, the commercial sector consumes both electricity and natural gas, as well as a limited quantities of other fuels. In comparison with the industrial sector, which produces "goods" for the economy, the commercial sector produces "services." As buildings are the primary category of end-use consumption for providing these services, this section identifies the many functions buildings perform and evaluates them in terms of their individual contributions to the production of CO_2 emissions.

Table 4-14. Utah Commercial Electricity Use

	Consumption (million kWh)	Customers (thousands)	kWh Per Customer
1990	5,389	62.8	85,752
1991	5,571	64.6	86,242
1992	5,850	66.4	88,167
1993	5,920	70.4	84,128
1994	6,341	70.8	89,525
1995	6,462	73.8	87,561
1996	6,717	75.8	88,649
1997	7,282	79.8	91,202
1998	7,433	82.4	90,237

Total electricity consumption in the Utah commercial sector is shown in Table 4-14. Also included are data for total commercial sector customers, which have grown from about 63,000 at the beginning of the 1990s to 82,376 by the decade's end. Average electricity consumption per customer, having stabilized at around 85,000 kWh for several years, has increased to over 90,000 kWh. This sector shows the same trend as that of households in the residential sector, with increasing average electricity per customer. The commercial sector has many components including retail and wholesale trade, financial, real estate, service, and communication industries. Energy in this sector is used in both large and small buildings ranging from 1,000 sq. ft. to over 100,000 sq, ft.

Natural gas use in the commercial sector is shown in Table 4-15. While average residential demand for natural gas varied somewhat within a range, average commercial demand markedly increased in the 1990s. Total commercial sector natural gas use began the decade at 16,220 mmcf and reached 30,955 mmcf by 1998, representing a total increase of 90.8 percent, with an annual average growth rate of about 11.4 percent. In contrast, natural gas customers increased from 34,697 to 42,054 in the decade, a total increase of 21.2 percent. The average annual growth rate of customers (2.4 percent) generally tracks the overall Utah population growth rate, yet the large increase in total natural gas demand by the commercial sector has resulted in a significant increase in average customer consumption.

Table 4-15. Utah Commercial Natural Gas Use

	Consumption (mmcf)	Customers (thousands)	mcf Per Customer
1990	16,220	34,697	467.5
1991	19,276	35,627	541.1
1992	16,584	36,145	458.8
1993	22,588	37,816	597.3
1994	26,501	39,183	676.3
1995	26,825	40,101	668.9
1996	29,543	40,107	736.6
1997	31,129	40,689	765.0
1998	30,955	42,054	736.1

Table 4-16. Utah Commercial CO_2 Emissions (in thousand tons)

	Natural Gas	Electric Sales	Electric Losses	All Other Fuels	Total
1990	1,028	1,829	4,000	917	7,774
1991	1,204	1,891	4,116	813	8,023
1992	1,041	1,985	4,240	858	8,124
1993	1,421	2,009	4,244	580	8,253
1994	1,648	2,151	4,489	516	8,804
1995	1,660	2,193	4,568	507	8,929
1996	1,792	2,279	4,744	687	9,502
1997	1,888	2,472	5,134	393	9,887
1998	1,877	2,522	5,251	631	10,281

Table 4-17. Utah Commercial CO_2 Emissions (as a percent)

	Natural Gas	Electric Sales	Electric Losses	All Other Fuels	Total
1990	13.2%	23.5%	51.5%	11.8%	100.0%
1991	15.0%	23.6%	51.3%	10.1%	100.0%
1992	12.8%	24.4%	52.2%	10.6%	100.0%
1993	17.2%	24.3%	51.4%	7.0%	100.0%
1994	18.7%	24.4%	51.0%	5.9%	100.0%
1995	18.6%	24.6%	51.2%	5.7%	100.0%
1996	18.9%	24.0%	49.9%	7.2%	100.0%
1997	19.1%	25.0%	51.9%	4.0%	100.0%
1998	18.3%	24.5%	51.1%	6.1%	100.0%

Table 4-18. Annual Growth in Utah CO_2 Emissions

	Natural Gas	Electric Sales	Electric Losses	All Other Fuels	Total
1991	17.2%	3.4%	2.9%	-11.3%	3.2%
1992	-13.6%	5.0%	3.0%	5.5%	1.3%
1993	36.5%	1.2%	0.1%	-32.5%	1.6%
1994	16.0%	7.1%	5.8%	-11.0%	6.7%
1995	0.7%	1.9%	1.8%	-1.6%	1.4%
1996	8.0%	3.9%	3.8%	35.4%	6.4%
1997	5.3%	8.5%	8.2%	-42.8%	4.0%
1998	-0.6%	2.0%	2.3%	60.5%	4.0%
TOTAL	82.7%	37.9%	31.3%	-31.2%	32.3%

B. Baseline Carbon Dioxide Emissions in the 1990s

Table 4-16 presents Utah commercial sector CO_2 emissions by fuel source. According to Table 4-17, over three-fourths of total CO_2 emissions are attributed to the consumption of electricity and associated losses. Natural gas measures nearly 18 percent of the total, with all other fuels amounting to about 7 percent, a fairly dramatic decline from 11 percent in 1990.

As with the residential sector, electricity losses are over twice the amount of electricity sales. Similarly, reducing or slowing electricity sales is an important way to reduce or slow CO_2 emissions in the commercial sector. For example, if commercial sector electricity consumption, which in 1998 resulted in about 2,522 thousand tons of CO_2, is reduced by 25 percent, or about 630 thousand tons, then the CO_2 emissions from the accompanying electricity losses are reduced by almost 1,300 thousand tons. Together, electricity sales and associated losses comprise over 75 percent of the total CO_2 emissions in the commercial sector. As compared with the 62 percent found in the residential sector, commercial sector electricity consumption represents an even larger proportion of total GHG emissions.

Table 4-19. Utah Commercial CO_2 Emissions in 1998 (in thousand tons)

	Electric Sales	Electric Losses	Natural Gas	All Other Fuels	Total
Space heating	107	223	1,054	379	1,763
Cooling	329	685	0	0	1,013
Ventilation	157	326	0	0	483
Water heating	45	95	503	126	769
Lighting	1,163	2,420	0	0	3,583
Cooking	18	38	191	0	248
Refrigeration	176	366	0	0	542
Office equipment	323	672	0	0	995
Other	204	425	130	126	885
Total	2,522	5,251	1,877	631	10,281

The annual growth rate of CO_2 emissions in the Utah commercial sector is shown in Table 4-18. As with the residential sector, natural gas use follows population trends with some variation due to weather patterns. Electricity demand, in contrast, has grown faster than population in recent years. With the Utah economy expanding at a record pace throughout the 1990s, electricity sales and their associated losses have even surpassed the overall growth in the Utah economy. Notably, electricity sales and associated losses have averaged 4.2 percent per year through the 1990s. All other fuels, primarily coal and LPG, have generally declined during the 1990s.

Table 4-20. Utah Commercial CO_2 Emissions in 1998 (as a percent)

	Electric Sales	Electric Losses	Natural Gas	All Other Fuels	Total
Space heating	1.0%	2.2%	10.2%	3.7%	17.1%
Cooling	3.2%	6.7%	0.0%	0.0%	9.9%
Ventilation	1.5%	3.2%	0.0%	0.0%	4.7%
Water heating	0.4%	0.9%	4.9%	1.2%	7.5%
Lighting	11.3%	23.5%	0.0%	0.0%	34.8%
Cooking	0.2%	0.4%	1.9%	0.0%	2.4%
Refrigeration	1.7%	3.6%	0.0%	0.0%	5.3%
Office equipment	3.1%	6.5%	0.0%	0.0%	9.7%
Other	2.0%	4.1%	1.3%	1.2%	8.6%
Total	24.5%	51.1%	18.3%	6.1%	100.0%

The Utah Commercial Sector and Tourism

The Governor's Office of Planning and Budget (GOPB) notes that the 2002 Winter Olympics has accelerated a number of projects on the drawing board that would have occurred without the Olympics. For example hotel construction, greatly speared by expected high occupancy rates, would have occurred over a 10-year time period instead of the current 5-year time period. The GOPB estimates that 25 percent of hotel construction has been accelerated so that the facilities will be in place prior to the games. In addition to hotels, a variety of other infrastructure investments will be affected by the Winter Olympics, including public facilities, such as the Salt Lake International Airport, various highways and transit systems, and private facilities, such as ski resorts. Some projects, such as the Winter Olympic venues and access roads are built specifically for the Games. In other cases, only the timing of the infrastructure investment is affected. The end result is more economic activity from 1996 to 2002 than would otherwise have occurred. This investment in infrastructure, particularly transportation infrastructure, has implications for Utah's GHG emissions. Tourism-related pollution has already become a problem in some areas. For example, increases in smog from vehicles have forced the National Park Service to close some areas to automobile touring. Similarly, high traffic volumes in Summit County, Utah – home to world-renowned recreational facilities – have resulted in increased air pollution that may eventually jeopardize the attractiveness of the area as a resort destination.

In spite of slower growth in tourism spending and visitation in 1997 and 1998, The GOPB forecasts that tourism will grow considerably as Utah receives increased awareness due to the 2002 Olympic Winter Games. Foreign exchange rates, airfares and direct international flights to Salt Lake International Airport are other major factors to consider. National travel trends point toward increasing interest in ecotourism, heritage tourism, and soft-adventure activities. Utah is well-positioned to attract those visitors seeking a higher quality, more unique experience and who are willing to pay more and stay longer. By focusing on quality over quantity, tourism can provide higher quality earnings, with fewer of the challenges often associated with "windshield" tourism.

C. The Matrix of Commercial Energy Use and CO_2 Emissions

For the year 1998, Table 4-19 describes how energy is used in the commercial sector and, correspondingly, how this consumption translates into GHG emissions by energy source and end use. The matrix, according to Table 4-20, shows electricity and natural gas as the primary energy sources consumed in the state, representing 75 percent (including losses) and 18 percent of GHG emissions respectively. Lighting accounts for over a third of these emissions, followed by space heating (17.9 percent), cooling (9.8 percent) and office equipment (9.6 percent). The balance of emissions is found in a wide array of other end uses.

IV. Utah Industrial Sector and CO_2 Emissions.

A. Overview of Aggregate Trends

The Utah industrial sector began the 1980s with annual consumption of almost 218 trillion Btu. In reaction to the steep increase in energy prices in the late 1970s, as well as local Utah conditions, the industrial sector energy demand fell considerably. For example, Geneva Steel in Provo shutdown for several years in the mid-1980s. By 1987, Utah industrial energy demand fell to less than 150 trillion Btu, a decline of almost one third since the beginning of the decade. Since 1987, however, Utah industrial energy demand has recovered with sustained growth in every year through 1998. At the end of the 1990s, Utah industrial energy demand was above 250 trillion Btu.

Table 4-21 depicts these trends, including energy intensity measured as total industrial energy use in million Btu per dollar of industrial Gross State Product (GSP). GSP is a measure of the value of output at the state level and is conceptually similar to Gross Domestic Product (GDP).

Table 4-21. Utah Industrial Energy Use

	Industrial Energy Use (Trillion Btu)	Industrial GSP (million dollars)	Industrial Energy Use per GSP dollar (million)
1980	218.5	5,528	39.5
1981	209.4	5,669	36.9
1982	187.3	5,448	34.4
1983	196.7	5,619	35.0
1984	198.1	6,433	30.8
1985	182.9	7,052	25.9
1986	158.1	6,706	23.6
1987	147.6	6,706	22.0
1988	197.2	7,321	26.9
1989	208.7	7,292	28.6
1990	213.2	7,792	27.4
1991	218.6	8,279	26.4
1992	211.9	8,347	25.4
1993	214.7	8,850	24.3
1994	215.4	9,845	21.9
1995	245.3	10,652	23.0
1996	251.8	11,364	22.2
1997	249.7	11,705	21.3
1998	254.7	12,056	21.1

B. Baseline Utah Industrial Sector CO_2 Emissions in the 1990s

The Utah industrial sector presents a more complicated picture than either the residential or commercial sector. In addition to natural gas and electricity, substantial amounts of coal are also consumed. Table 4-22 presents Utah industrial sector CO_2 emissions by fuel. Nearly half of these emissions are associated with electricity sales and losses. Natural gas and coal each account for about a quarter, followed by distillate fuel and all other fuels. Table 4-24 shows a large degree of year-to-year variation in energy use by fuel.

Table 4-22. Utah Industrial CO_2 Emissions (in thousand tons)

	Coal	Natural Gas	Distillate Fuel	All Other Fuels	Electric Sales	Electric Losses	Total
1990	4,477	3,499	700	346	1,957	4,280	15,258
1991	4,521	3,550	880	236	1,994	4,340	15,521
1992	3,925	3,355	906	272	2,108	4,502	15,069
1993	3,981	3,449	850	350	2,111	4,460	15,202
1994	4,313	3,104	831	440	2,205	4,601	15,495
1995	3,983	4,292	745	598	2,361	4,918	16,897
1996	3,827	4,208	853	762	2,599	5,410	17,658
1997	4,140	4,163	1,115	801	2,521	5,236	17,982
1998	4,185	4,416	1,160	833	2,549	5,306	18,448

Table 4-23. Utah Industrial CO_2 Emissions (as a percent)

	Coal	Natural Gas	Distillate Fuel	All Other Fuels	Electric Sales	Electric Losses	Total
1990	29.3%	22.9%	4.6%	2.3%	12.8%	28.0%	100.0%
1991	29.1%	22.9%	5.7%	1.5%	12.8%	28.0%	100.0%
1992	26.0%	22.3%	6.0%	1.8%	14.0%	29.9%	100.0%
1993	26.2%	22.7%	5.6%	2.3%	13.9%	29.3%	100.0%
1994	27.8%	20.0%	5.4%	2.8%	14.2%	29.7%	100.0%
1995	23.6%	25.4%	4.4%	3.5%	14.0%	29.1%	100.0%
1996	21.7%	23.8%	4.8%	4.3%	14.7%	30.6%	100.0%
1997	23.0%	23.1%	6.2%	4.5%	14.0%	29.1%	100.0%
1998	22.7%	23.9%	6.3%	4.5%	13.8%	28.8%	100.0%

Table 4-25. Utah Industrial CO_2 Emissions in 1998 (in thousand tons)

	Coal	Natural Gas	Distillate Fuel	All Other Fuels	Electric Sales	Electric Losses	Total
Process	418	530	70	42	1,657	3,449	6,165
Process heating	3,766	1,855	777	567	204	424	7,593
Process cooling	0	0	0	0	178	371	550
Space heating	0	1,501	139	175	25	53	1,894
Space cooling	0	0	0	0	127	265	393
Lighting	0	0	0	0	153	318	471
Ventilation	0	0	0	0	127	265	393
Water heating	0	353	116	42	25	53	589
Other	0	177	58	8	51	106	400
Total	4,185	4,416	1,160	833	2,549	5,306	18,448

As electricity losses are more than twice the amount of electricity sales, reducing or slowing sales is an important way to reduce or slow CO_2 emissions. For example, if industrial sector electricity consumption, which in 1998 resulted in about 2,549 thousand tons of CO_2, is reduced 25 percent, or by about 637 thousand tons, then the CO_2 emissions from the accompanying electricity losses are reduced by about 1,327 thousand tons of CO_2. Together, electricity sales and their associated losses comprise about 43 percent of the total CO_2 emissions in the Utah industrial sector. This should be compared to the 62 percent found in the Utah residential sector and the 75 percent in the Utah commercial sector.

C. The Matrix of Industrial Energy Use and CO_2 Emissions

To understand how energy is used in the industrial sector, and the associated level of CO_2 emissions, a matrix of industrial energy sources and end uses was developed. The matrix for the Utah industrial sector in 1998 is shown in Table 4-25, with percentages shown in Table 4-26.

Table 4-24. Annual Growth in Utah Industrial CO_2 Emissions

	Coal	Natural Gas	Distillate Fuel	All Other Fuels	Electric Sales	Electric Losses	Total
1991	1.0%	1.5%	25.8%	-31.9%	1.9%	1.4%	1.7%
1992	-13.2%	-5.5%	2.9%	15.5%	5.7%	3.7%	-2.9%
1993	1.4%	2.8%	-6.1%	28.6%	0.2%	-0.9%	0.9%
1994	8.3%	-10.0%	-2.2%	25.7%	4.5%	3.2%	1.9%
1995	-7.6%	38.3%	-10.4%	35.7%	7.1%	6.9%	9.1%
1996	-3.9%	-2.0%	14.4%	27.5%	10.1%	10.0%	4.5%
1997	8.2%	-1.1%	30.8%	5.9%	-3.0%	-3.2%	1.8%
1998	1.1%	6.1%	4.0%	3.3%	1.1%	1.3%	2.6%
TOTAL	**-6.5%**	**26.2%**	**65.8%**	**140.9%**	**30.3%**	**24.0%**	**20.9%**

V. Utah Transportation Sector and CO_2 Emissions

A. Overview of Aggregate Trends

Although many fuels are used in the Utah transportation sector, the largest category of consumption is motor gasoline for automobiles. Other significant fuels include diesel fuel, which is used for both truck and rail transportation, as well as jet fuel used for air transportation.

Table 4-27 indicates that, between 1990 and 1998, Utah gasoline consumption increased a total of 37.2 percent, or about 4.7 percent a year, from 690.1 to 946.6 million gallons. Average consumption per automobile, during the same decade, increased from 887 to 1,091 gallons per automobile per year, representing a total change of 23 percent, or about 2.9 percent per year.

Closely related to the growth in motor gasoline demand is the growth in the number of automobiles and vehicle-miles traveled. Table 4-28 displays the number of Utah registered automobiles, automobile vehicle-miles traveled (VMTs), and average vehicle-miles traveled per automobile. Between 1990 and 1998, Utah automobiles have increased a total of 11.6 percent, or about 1.4 percent a year, from 777,906 to 867,828. Yet over the same period, automobile VMTs dramatically increased by a total of 45.2 percent, or about 5.7 percent a year, from 9.8 to 14.3 billion miles. Average miles per automobile is one of many measures of transportation sector intensity of use. This amount increased during this time period 30.2 percent, or about 3.8 percent a year, from 12,614 to 16,421 miles per automobile per year. Finally, miles per gallon (MPG) is the primary measure of transportation sector fuel efficiency. During this decade, MPG remained constant at about 22 miles per gallon.

Table 4-26. Utah Industrial CO_2 Emissions in 1998 (as a percent)

	Coal	Natural Gas	Distillate Fuel	All Other Fuels	Electric Sales	Electric Losses	Total
Process	2.3%	2.9%	0.4%	0.2%	9.0%	18.7%	33.4%
Process heating	20.4%	10.1%	4.2%	3.1%	1.1%	2.3%	41.2%
Process cooling					1.0%	2.0%	3.0%
Space heating		8.1%	0.8%	0.9%	0.1%	0.3%	10.3%
Space cooling					0.7%	1.4%	2.1%
Lighting					0.8%	1.7%	2.6%
Ventilation					0.7%	1.4%	2.1%
Water heating		1.9%	0.6%	0.2%	0.1%	0.3%	3.2%
Other		1.0%	0.3%		0.3%	0.6%	2.2%
Total	22.7%	23.9%	6.3%	4.5%	13.8%	28.8%	100.0%

B. Baseline UtahCO_2 Emissions in the 1990s

The Utah transportation sector primarily uses motor gasoline, diesel fuel, and jet fuel for highway, railroad, and airline energy. Table 4-29 presents Utah transportation sector energy-related CO_2 emissions.

Table 4-27. Utah Gasoline Consumption

	Gasoline Consumption (thousand gallons)	Average Consumption per Automobile (gallons)
1990	690,060	887
1991	718,284	942
1992	740,292	998
1993	779,898	1,004
1994	802,074	1,007
1995	857,976	1,065
1996	874,356	1,078
1997	910,140	1,070
1998	946,554	1,091

Table 4-28. Utah Automobiles and Miles Traveled

	Automobiles	Vehicle-Miles Traveled (millions)	Average Annual Miles per Automobile
1990	777,906	9,813	12,614
1991	762,179	10,312	13,530
1992	741,713	10,926	14,730
1993	776,484	11,428	14,717
1994	796,877	12,112	15,200
1995	805,609	12,583	15,620
1996	811,383	13,091	16,134
1997	850,812	13,697	16,099
1998	867,828	14,251	16,421

I-15 Reconstruction

In spring 1997, the Utah Department of Transportation (UDOT) began a reconstruction project of I-15. The goal of this four-and-a-half year project is to remove the Salt Lake section of I-15, which had outlived its life span by about 20 years, and then to reconstruct a highway that would meet the expected highway demand in Salt Lake for the next 50 years.

The scale of the project is impressive with an estimated cost of $1.59 billion. The length of the freeway is roughly 17 miles and UDOT estimates that it will use more than 5 million cubic yards of fill material (about 360,000 dump truck loads) during I-15 reconstruction. The project includes the replacement of more than 144 bridges and frontage road improvements. The "Design-Build" approach to construction is also noteworthy. It is the largest project ever attempted using this method, where the same contracting team both designs and builds the project. This method allows the contracting team to construct some sections while other sections are still in the final design phase.

Traffic capacity on I-15 will be bolstered by an increase in lanes to a total of twelve -- six in each direction -- including new, high-occupancy vehicle (HOV) lanes. However, improved freeway capacity will likely increase GHG emissions as more people move into suburban areas and as across-valley commutes become easier to make.

Table 4-29. Utah Transportation CO_2 Emissions (in thousand tons)

	Distillate Fuel	Motor Gasoline	Jet Fuel	All Other Fuels	Total
1990	2,444	6,704	2,364	181	11,693
1991	2,412	6,979	2,649	155	12,194
1992	2,544	7,193	2,510	189	12,435
1993	2,606	7,577	2,470	261	12,915
1994	2,774	7,793	2,359	271	13,197
1995	3,244	8,336	2,533	257	14,370
1996	3,456	8,495	2,822	300	15,072
1997	3,793	8,843	2,810	259	15,704
1998	3,717	9,196	2,852	251	16,016

Motor gasoline, as a share of total Utah transportation sector energy use, has remained constant throughout the decade of the 1990s at between 56 and 59 percent. While jet fuel has declined from almost 22 percent at the beginning of the decade to about 18 percent by 1998, diesel fuel use has noticeably increased. Diesel fuels have almost reversed the jet fuel pattern and grown from about 20 percent to almost 24 percent of Utah transportation-related energy use. Unlike the residential, commercial and industrial sectors, very little electricity is used by the transportation sector. The annual growth in Utah transportation energy use is given in Table 4-31. Overall, the sector has shown strong growth at over 4 percent a year this decade. Not only are transportation-related motor gasoline and diesel fuel significant contributors to GHG emissions, both have demonstrated sustained growth. In some cases, this sustained growth has been well above 4 percent.

Table 4-30. Utah Transportation CO_2 Emissions (as a percent)

	Distillate Fuel	Motor Gasoline	Jet Fuel	All Other Fuels	Total
1990	20.9%	57.3%	20.2%	1.5%	100.0%
1991	19.8%	57.2%	21.7%	1.3%	100.0%
1992	20.5%	57.8%	20.2%	1.5%	100.0%
1993	20.2%	58.7%	19.1%	2.0%	100.0%
1994	21.0%	59.1%	17.9%	2.1%	100.0%
1995	22.6%	58.0%	17.6%	1.8%	100.0%
1996	22.9%	56.4%	18.7%	2.0%	100.0%
1997	24.2%	56.3%	17.9%	1.6%	100.0%
1998	23.2%	57.4%	17.8%	1.6%	100.0%

Table 4-31. Annual Growth in Utah Transportation CO_2 Emissions

	Distillate Fuel	Motor Gasoline	Jet Fuel	All Other Fuels	Total
1991	-1.3%	4.1%	12.1%	-14.1%	4.3%
1992	5.5%	3.1%	-5.2%	21.7%	2.0%
1993	2.5%	5.3%	-1.6%	38.1%	3.9%
1994	6.4%	2.8%	-4.5%	3.9%	2.2%
1995	17.0%	7.0%	7.4%	-5.2%	8.9%
1996	6.5%	1.9%	11.4%	16.8%	4.9%
1997	9.8%	4.1%	-0.4%	-13.6%	4.2%
1998	-2.0%	4.0%	1.5%	-3.3%	2.0%
TOTAL	**52.1%**	**37.2%**	**20.6%**	**44.7%**	**37.0%**

C. The Matrix of Transportation Energy Use and CO_2 Emissions

To understand how energy is used in the transportation sector, and the resulting CO_2 emissions, a matrix of transportation energy sources and end uses was developed. The matrix for the Utah transportation sector in 1998 is shown in Table 4-32. The transportation sector relies on motor gasoline diesel fuel, and jet fuel, with smaller amounts of other fuels. Electricity is not used and natural gas plays a small role. Most of the natural gas used in the transportation section is used as pipeline fuel, although vehicle conversion to natural gas shows promise in the future.

Table 4-32. Utah Transportation CO_2 Emissions in 1998 (in thousand tons)

	Gasoline	Diesel	Jet fuel	All Other Fuels	Total
HIGHWAY	8,912	2,738		1	11,651
Automobiles	5,106	88		1	5,194
Motorcycles	15				15
Buses	19	100		1	120
Trucks	3,772	2,551			6,322
Light trucks	3,413	152			3,565
Other trucks	358	2,399			2,757
OFF-HIGHWAY	90	718			808
Construction	21	435			456
Agriculture	69	284			353
NON-HIGHWAY	194	521	2,852	249	3,817
Air	21		2,852		2,873
Water	174				174
Freight					
Recreational	174				174
Rail		521			521
Freight		503			503
Passenger		19			19
Total	9,196	3,717	2,852	251	16,016

Table 4-33. Utah Transportation CO_2 Emissions in 1998 (as a percent)

	Gasoline	Diesel	Jet fuel	All Other Fuels	Total
HIGHWAY	55.6%	17.1%		0.1%	72.7%
Automobiles	31.9%	0.5%		0.1%	32.4%
Motorcycles	0.1%				0.1%
Buses	0.1%	0.6%		0.1%	0.8%
Trucks	23.5%	15.9%			39.5%
Light trucks	21.3%	0.9%			22.3%
Other trucks	2.2%	15.0%			17.2%
OFF-HIGHWAY	0.6%	4.5%			5.0%
Construction	0.1%	2.7%			2.8%
Agriculture	0.4%	1.8%			2.2%
NON-HIGHWAY	1.2%	3.3%	17.8%	99.6%	23.8%
Air	0.1%		17.8%		17.9%
Water	1.1%				1.1%
Freight	0.0%				
Recreational	1.1%				1.1%
Rail		3.3%			3.3%
Freight		3.1%			3.1%
Passenger		0.1%			0.1%
Total	57.4%	23.2%	17.8%	1.6%	100.0%

By category, highway transportation accounts for nearly three-fourths of total CO_2 emissions, followed by the non-highway (24 percent) and off-highway (5 percent) categories. Within the highway category, trucks account for the largest share at nearly 40 percent compared with automobiles (32 percent). Emissions due to off-highway uses, including agriculture and construction, are marginal as well. Finally, in the non-highway sector, air transportation is the dominant source of emissions with minor contributions from rail and recreational transportation.

VI. Utah Electric Utility Sector and CO_2 Emissions

A. Overview of Aggregate Trends

Approximately 95 percent of total electric power in Utah is generated by coal-fired plants. Of this total, some 90 percent is generated from only 5 large coal-fired plants operating at high capacity factors (85-90 percent). When examining GHG emissions from a fuel input perspective, as opposed to end-use consumption, it is clear that these five plants account for the majority of CO_2 emissions.

Fuel consumption at Utah electric power plants is shown in Table 4-34. Coal consumption by Utah electric utilities grew a total of 7.2 percent in the decade of the 1990s, reflecting an annual average growth rate of 0.9 percent. Natural gas is used by Utah electric utilities as a seasonal peaking fuel, and its growth is much more difficult to evaluate since demand patterns are more erratic. In 1991, natural gas demand was about 5.2 billion cubic feet (Bcf). Over the next several years it shot upwards to near 9.0 Bcf, only to return to 5.3 Bcf in 1998.

Light fuel oil is the third fuel used at Utah electric utilities and is used as a start-up fuel for a large coal-fired power plant. Distillate fuel oil in 1998 was at 63 percent of its 1990 level representing an average annual decline rate of 4.6 percent.

B. Baseline Utah Electric Utility Sector CO_2 Emissions in the 1990s

The Utah electric utility sector produces about 60 percent of the state's total CO_2 emissions. While coal-fired steam generation fluctuates around 94-95 percent of total electric power generation, coal consumption by Utah's electric utilities results in 99 percent of Utah's electric utility CO_2 emissions. Natural gas and distillate fuel oil contribute small amounts

C. Electric Utility Energy Use and CO_2 Emissions

Unlike the previous energy-consuming sectors, the electric utility sector is strictly a supply resource; therefore, there are no end uses associated with electric power generation per se. Nevertheless, it is important to understand the fundamentals of the industry in order to better appreciate the scale and scope of the industry's contribution to CO_2 emissions. The following, therefore, includes a brief overview of the industry's structure, operation, and performance.

Table 4-34. Electric Utility Fuel Consumption

	Coal (Short Tons)	Natural (bcf)	Distillate (Barrels)
1990	14,053,000	0.843	84,000
1991	13,472,000	5.190	82,000
1992	13,136,000	6.576	62,000
1993	13,343,000	6.305	55,000
1994	13,839,000	8.900	53,000
1995	12,550,000	8.707	61,000
1996	12,728,000	3.428	55,000
1997	14,780,000	4.079	52,000
1998	14,545,000	5.268	53,000

As noted, Utah's coal-fired generation dominates production (approximately 95 percent), with approximately 4 percent contributed by hydroelectric resources. The remainder is composed of natural gas, other fossil fuels, and geothermal sources.

Of the coal production, PacifiCorp-owned Utah Power (UP) owns and operates roughly 52 percent of all coal-fired facilities in the state. Since January 1998, the capacity factor (a measure of output ability) at UP's plants has been high, though four out of seven units to date are registering declines over 1997 year averages.

The Intermountain Power Project (IPP), a 1,660 MW coal-fired facility, continues to account for a substantial share of coal-fired generation. Positioning itself for increased competition in California, the state with which it has a long-term power contract, IPP has cut cost dramatically, including 76 staff positions in 1997 alone. With only 472 employees, the IPP facility has recently garnered industry recognition for its efficient operations. A recent industry article on the nation's top 100 facilities ranked IPP as 68th in generation, 43rd in cost of operation, 19th in heat rate (Btu/kWh), and 2nd in capacity factor. Revised estimates show gross generation (including auxiliary power) having increased from 11,365.1 GWh in 1996 to 13,482.4 GWh in 1997. Year-end calculations put IPP generation at 13,624 GWh, a potentially record setting year.

Table 4-35. Utah Coal-fired Power Plant Capacity

	Megawatts (MW)
IPP	1,640
Hunter	1,415
Huntington	896
Bonanza	400
Carbon	189
Non-coal	771
State total	5,311

Table 4-36. Utah Electric Utility CO_2 Emissions (in thousand tons)

	Coal	Natural Gas	Distillate Fuel	Total
1990	32,852	49	39	32,940
1991	31,494	322	38	31,854
1992	30,708	411	29	31,148
1993	31,192	390	26	31,608
1994	32,352	541	25	32,917
1995	29,338	535	28	29,901
1996	29,755	204	26	29,984
1997	34,552	247	24	34,822
1998	34,002	360	25	34,387

Table 4-37. Utah Electric Utility CO_2 Emissions (as a percent)

	Coal	Natural Gas	Distillate Fuel	Total
1990	99.7%	0.1%	0.1%	100.0%
1991	98.9%	1.0%	0.1%	100.0%
1992	98.6%	1.3%	0.1%	100.0%
1993	98.7%	1.2%	0.1%	100.0%
1994	98.3%	1.6%	0.1%	100.0%
1995	98.1%	1.8%	0.1%	100.0%
1996	99.2%	0.7%	0.1%	100.0%
1997	99.2%	0.7%	0.1%	100.0%
1998	98.9%	1.0%	0.1%	100.0%

Composed of six members, the Utah Municipal Power Agency (UMPA) generated 859,979 MWh through June 1998, a 3.14 percent increase over the comparable period in 1997. For its non-members, including customers on the western grid, sales increased sharply from 32,211 GWh in 1997 to 169,674 GWh in 1998. Peak demand also increased by 5.27 percent over the year.

UMPA provides its members with electricity from several sources. Its 3.75 percent share in Deseret Generation and Transmission's Bonanza Unit 1 produced 259,304,410 kWh in FY 98, a 2.4 percent increase over last year. Overall, the Bonanza facility, coal-fired unit, accounted for 28.5 percent of UMPA's energy sources. In addition, through a 6.5 percent share in UP's Hunter I coal-fired unit, UMPA produced 140,878,000 kWh from 27 MW, an 11.4 percent increase over the 1997 level. Hunter 1 accounts for 15.5 percent of UMPA's total sources.

Table 4-38. Annual Growth in Utah Electric Utility CO_2 Emissions.

	Coal	Natural Gas	Distillate Fuel	Total
1991	-4.1%	556.5%	-2.4%	-3.3%
1992	-2.5%	27.5%	-24.4%	-2.2%
1993	1.6%	-5.1%	-11.3%	1.5%
1994	3.7%	38.6%	-3.6%	4.1%
1995	-9.3%	-1.1%	15.1%	-9.2%
1996	1.4%	-61.9%	-9.8%	-0.3%
1997	16.1%	21.2%	-5.5%	16.1%
1998	-1.6%	45.8%	1.9%	-1.3%
TOTAL	**3.5**	**11.6**	**-36.9**	**4.4**

By far, the largest share of UMPA power (42.3 percent) is purchased from the Colorado River Storage Project (CRSP), which is operated by the Western Area Power Administration (WAPA). From CRSP's 93.57 MW of maximum available capacity, the UMPA purchased 384,927,456 kWh, an 8 percent increase over 1997 levels. The balance of UMPA's purchases include smaller shares of several plants including the Bonnett plant (geothermal), several hydroelectric facilities, the Provo Power Plant, the Deer Creek plant, and several PacifiCorp contracts.

Utah Associated Municipal Power Systems (UAMPS) logged 3,350,651 MWh in total system sales (including purchased power contracts), a 10.4 percent increase over the 1997 amount. Sales to members increased by 6 percent over the year, though off-system sales plummeted by 46 percent.

Overall, UAMPS energy sales increased by 1.9 percent from 2,273,323 MWh in 1997 to 2,316,397 in 1988. Increased sales are largely attributed to demand from Idaho Falls, a new UAMPS member. Recent estimates indicate that Idaho Falls has 21,725 customers, requiring 631,908,602 kWh with a peak demand of 138,446 kW.

With generation from its 430 MW coal-fired plant, supplemented by federal power contracts and a 25.1 percent share in PacifiCorp's Hunter II facility, Deseret Generation & Transmission serves 38,432 residential-farm and non-farm customers in six member districts throughout Utah and neighboring states. Total 1997 sales reached 3,849,797 MWh with a slight shift from member to non-member sales. Six new industrial customers have been added to the DG&T system, leading analysts to project a 5.5 percent increase in 1998 for total sales of 4,052,415 MWh in 1998.

Improvements in operations of the Bonanza coal-fired plant has boosted DG&T's competitiveness in recent years. According to DG&T plant availability, which includes both planned and unplanned outages, increased to 94.8 percent in 1997 and is projected to reach 97.8 percent in 1998.

Deregulation

For the past several years, electric industry analysts have watched and waited for federal and state actions on deregulation. While the precise effect of deregulation is unknown at this time, an important result of deregulation should be the continued demand in California for IPP electric power exports. Should Utah electric power exports remained at or near the current level of 13,000 million kWh per year, Utah in-state consumption of electric power will need to be met by increased imports from the Pacific Northwest. These imports will be generated by a mix of fuels but will have a large hydro-power component.

VII. Assessment of Potential Energy Savings

Encouraging energy efficiency in all sectors of the Utah economy is of paramount important importance in reducing GHG emissions. As approximately 85 percent of Utah's total GHG emissions are linked to fossil fuel consumption, the prime areas for reduction include the electric utility sector and the transportation sector. In the electricity sector, opportunities exist in both supply and demand, the former including electric generation technologies, including fuel substitution, and the latter including demand-side management strategies. In the transportation sector, a wide range If strategies exist for improving both the technical performance of transportation modes, expanding the range of modes used, and in fuel substitution as well.

The non-fossil sector, which accounts for the remaining 15 percent of carbon emissions (in CO_2 equivalent measures) covers a diverse set of economic sectors. Most of these sectors involve industrial productivity for which mitigation strategies must be targeted at the level of the industrial processes. Other non-fossil strategies relate to the recovery of potentially fugitive emissions in the public works (waste management) sector and in industry.

Residential Sector

As compared with Utah's other energy consuming sectors, the options for mitigation in the residential sector are relatively restricted. While households may elect to purchase supply-side technologies such as solar or micro turbines, the capital costs are frequently prohibitive thus forcing most residential energy customers to rely instead on less costly demand-side management and energy efficiency practices. While new federal standards for appliances may be instituted, it is likely that fuel substitution will remain a key mitigation strategy as long as sufficient natural gas pipelines and supporting distribution infrastructure are in place. Furthermore, it is widely expected that competitive markets for electricity will include additional energy efficiency opportunities.

Commercial Sector

The commercial sector lends itself to a wide variety of options for GHG emissions reduction strategies. As with the residential sector, numerous opportunities exist for energy efficiency and demand-side management. In addition to building shell improvements, fuel substitution is also a preferred strategy. On the supply side, this sector can readily exploit district energy and cogeneration options. As compared with the residential sector, the commercial focus on profits compels energy customers in this sector to seek more cost-effective options.

Industrial Sector

The industrial sector accounts for a significant share of total GHG emissions. As with the commercial sector, a wide array of both supply and demand-side management mitigation strategies are available to this sector. In Utah, industrial customers have benefitted from many utility-sponsored energy-efficiency programs. Large-scale cogeneration options remain an attractive option and numerous energy-efficiency improvements are also available. In competitive electricity markets, industrial customers stand to benefit greatly from power marketing programs that will likely include energy-efficiency incentives.

Transportation Sector

It is evident from the statistics presented that the transportation sector is a major source of GHG emissions in Utah. A wide variety of mitigation measures is available and, for this research, generally fall into one of two categories: improvements to vehicle performance and infrastructure improvements. Vehicle performance issues are typically addressed at the Federal level through, for example, CAFE standards. At the state level, gasoline taxes may be applied to induce shifts in demand. Infrastructure improvements range from mass transit to high-occupancy vehicles (HOV) lanes.

Electric Utility Sector

Electric power generation in Utah is characterized by a high degree of reliance upon coal-fired facilities. Because of the high capital costs of electric power facilities, it is unlikely that either large-scale facilities using alternative fuels or renewable resources will be substituted for the currently existing and depreciated assets. Instead, it is far more realistic that, over the short and medium term, co-firing of natural gas will be used. Over the next few decades, combined-cycle facilities and generators with higher heat rates should result in higher efficiencies and, in consequence, lower GHG emissions.

The Non-Fossil Sector

As noted, the non-fossil sector accounts for roughly 15 percent of GHG emissions. Industrial processes (limestone, lime, and cement) account for a relatively small fraction of the total. Emissions in this category are linked to overall industrial productivity and construction activity in the state; however, opportunities for reduction are rather limited due to the challenges of finding

Deregulation and Greenhouse Gas Emissions

Many of its proponents argue that deregulation is the key to resolving a host of environmental problems associated with power generation. In theory, deregulation should promote the introduction of new technologies, both supply and end-use, that will contribute greatly to the reduction of CO_2 emissions. An additional benefit, associated with both wholesale and retail deregulation, is the prospect of exporting larger amounts of power to consumers throughout the west. While increased exports could result in greater emissions within Utah's borders, those importing Utah power will likely receive a considerable environmental benefit: power generated by coal sources which are among the world's cleanest and highest in Btu. In many instances, imported Utah power could "back out" generation from dirtier, lower Btu coals. Currently it is uncertain whether or not a deregulated market will allow for Utah's coal-fired power plants to produce more electricity for export. At issue is whether or not the relative marginal costs of power generation will operate in favor of Utah's electricity.

areas for improving basic chemical reactions. Emissions from industry operations, such as fossil fuel production and distribution, represent another possible area of reduction, though significant investment in infrastructure must be made. Finally, increased attention has been focused on public waste management operations in recent years. Notably, projects are currently proposed for both municipal wastewater and landfill methane capture.

Land Use Planning

As compared with the other sectors, land use planning does not readily lend itself to the analysis of individual GHG reduction measures. Specifically, the analysis is complicated by the fact that multiple energy-consuming activities, such as building energy consumption and transportation, are inextricably linked in a given land use plan. Therefore, it is virtually impossible to compare multiple land use plans and identify the specific reduction potential as one might in comparing, for example, different end-use efficiencies or modes of transportation. As a result, GHG reduction potential in this sector is discussed qualitatively with only rough estimates identified for planning variables such as mix of energy-consuming activities, land use designation, density, and siting. It should be noted, however, that land use planning may ultimately provide very significant savings since basic alterations in building and transportation infrastructure lead to relatively permanent changes in overall energy consuming activity.

Part Five

Fossil Fuel Mitigation Strategies

I. Overview

The Utah residential, commercial, industrial, transportation, and electric utility sectors are each examined for GHG mitigation strategies that satisfy the selection criteria established in Part Three. For several mitigation strategies in each sector, the CO_2 reduction quantity and its associated cost are reported for both feasible and potential strategies. The feasible category describes the likely reduction expected and is based on assumptions regarding technology and market penetration, as well as political and institutional acceptance. The cost data shown are in levelized dollars per CO_2 ton reduced in 2010. The cost data were levelized over a 30-year time horizon in order to make the different strategies comparable.

Due to the cross-sectoral nature of GHG emissions associated with various land use patterns, this section also includes a separate discussion on land use planning-related mitigation opportunities. This discussion represents a broader, system-wide approach to GHG emissions mitigation that may help to augment reductions made in each sector.

II. Residential Sector

A. Introduction

Although the residential sector contributes least to GHG emissions as compared with other sectors, this sector is important for several reasons. First, it encompasses the physical structures in which we live and the end-use of the technologies that make these structures comfortable. Clearly our standard of living depends on conveniences such as heating and refrigeration. Second, the residential sector also represents a substantial investment of individual stakeholders within our community. For most people, purchasing a home is the most significant investment that they will make. Even for renters, the total amount of money devoted to provide housing relative to other expenses is large. The average Utahn spends about 30 percent of their income on housing each year. Third, with regard to GHG emissions, the residential sector lends itself well to mitigation measures. For example many people with older appliances (which usually use more energy than newer appliances) would save money in the long run if they chose to purchase a more energy-efficient appliance. In addition, many people buy new appliances with no thought as to energy efficiency, so the turnover of the appliance stock allows for gradual, ongoing improvement. Fourth, the residential sector is growing. This growth is largely the result of substantial population growth, most of which is due to the state's relatively high fertility rate (2.6 annually compared to the national average of 2.0).

The Utah residential sector is forecast to release 11.6 million tons of CO_2 by the year 2010, up from 7.8 million tons of CO_2 in 1990. This represents a total increase of 49.2 percent, or about 2.5 percent a year. The residential sector accounted for 18.4 percent of Utah's energy-related CO_2 emissions in 1990 and decreased to 17.9 percent in 1998. By 2010, it should account for 16.7 percent of Utah's GHG emissions.

The typical household in Utah is responsible for about 14 tons of CO_2 emissions annually. Considering both electricity sales and their associated losses, most of the emissions in the residential sector, about 62 percent, result from electricity use. Computers, hair dryers, electric stoves, and other major and minor appliances are powered from an external source. In Utah, this source usually consists of power plants, with about 95 percent of power generation from coal-fired sources. Each kWh delivered to the end user at the electric outlet results in about 2.37 pounds of CO_2 generated by a power plant.

Strategies to reduce emissions in this sector can be separated into two main areas. The first category is major electricity end uses, which includes space heating, water heating, refrigerators, and air conditioning, while the second category includes lighting and appliances. An interesting aspect of appliances is that this category can also be divided into major and minor uses. Major appliances are such things as washing machines and clothes dryers. Minor appliances include everyday household items such as electric razors, blenders, and can openers. While reductions can be obtained within all appliances, this report focuses on major appliances. One of the criteria in selecting strategies was that of identifying meaningful strategies of GHG emissions reductions. Though strategies for minor appliances taken as a whole could lead to a meaningful reduction, as individual appliances they do not lead to major reductions.

The second type of strategy is to change living conditions and behavior. This type of strategy is not as neatly defined as energy efficiency measures but it is useful. This type of strategy might involve changing "structural" elements of a residence. For example, the type and quality of insulation and windows play an important role in determining the amount of energy used to create heat and air conditioning. This category of strategies also tries to alter household behavior. An illustration of this might be a strategy that tries to promote conservation through a public awareness campaign. Alternatively, conservation could also be encouraged through increasing the cost of electricity through taxes or other measures.

B. Selected Strategies

Major Appliance Efficiency Gains

Major appliances include refrigerators and freezers, cooking appliances, clothes washers and dryers, and dishwashers. These appliances differ from minor appliances in the amount of electricity they require to operate. Reducing the amount of electricity that is needed to operate major appliances may be an attractive strategy for several reasons. First, increasing the efficiency of major appliances leads to a reduction in GHG emissions. Second, assuming that the cost of increasing efficiency of these appliances is modest, these improvements will pay for themselves in the form of decreased electricity bills. Third, improving appliance efficiency allows for a relatively painless transition. As the stock of appliances turns over, more efficient appliances replace less efficient appliances.

Electric Water Heater to Natural Gas Conversion

Approximately 33 percent of water heaters in Utah are electric, and electric water heaters account for 13 percent of residential electricity use. Natural gas provides a cheaper and more efficient energy source for water heating and results in less CO_2 emissions. Conversion to natural gas has the potential to reduce CO_2 emissions 64,000 tons at $20 per ton. A feasible strategy reduces CO_2 emissions by 10,000 tons at less than $30 per ton.

Refrigerators

Refrigerators and freezers account for 15 percent of electricity use in the Utah residential sector. Much can and has been done to increase energy efficiency of these products. Models made in the 1970's use nearly 2.5 times more energy than those sold on the market today. Some refrigerators and freezers may use 20 percent less energy than the model standards set in 1993, with some models reaching reductions of up to 40 percent.

Many of the energy-efficiency improvements are simple. For example, models with side-by-side freezers and refrigerators use more energy than those with a freezer situated above the refrigerator. The minimum energy efficiency standard for refrigerators and freezers made after 2001 is between 23 percent to 30 percent more efficient than the current level (set in 1993). The average refrigerator in Utah uses approximately 1,155 kWh per year; the average freezer uses 1,200 kWh per year. Conservatively assuming that the stock of refrigerators and freezers in Utah meets the minimum 1993 levels, and that these appliances will average a 25 percent efficiency gain, the average refrigerator sold after 2001 will use less than 850 kWh per year, and the average freezer sold after 2001 will use less than 900 kWh per year. A feasible strategy reduces CO_2 emissions by 9,000 tons at $45 per ton. Premium refrigerators have the potential to reduce CO_2 emissions 150,000 tons at $45 per ton.

Clothes Dryers

Clothes dryers account for approximately six percent of energy use in the Utah residential sector. However, clothes dryers do not present a significant opportunity for reductions in energy use. New technologies may be introduced that lead to reductions. This report, however, makes the conservative assumption that significant reductions are not feasible by 2010.

Clothes Washers

Clothes washers use more than nine percent of the electricity within the Utah residential sector. The amount of energy a clothes washer uses is determined largely by design. For example, a tub that is front loading rather than top loading saves energy. Another factor to consider is the amount and temperature of water used per load. Energy-efficient clothes washers use less water, particularly hot water, than less efficient clothes washers.

The EPA's Energy Star® program has identified washers that are at least 30 percent more energy efficient than those that meet the minimum standards and confers an Energy Star® rating on those machines if they meet a higher energy-efficiency standard. These more energy-efficient products often cost more, but they frequently pay for themselves through a reduction in consumer energy bills. Energy-efficient clothes washers have additional benefits as well. Energy Star® reports than in addition to using 30-40 percent less energy, these washers use 50 percent less water, cause less wear and tear on clothes, and extract water better, which may lead to an addition energy savings when a clothes dryer is used.

Residential Indoor Lighting

Indoor lighting accounts for approximately 12 percent of electricity use in the Utah residential sector. Lighting is a subtle energy user because it is the cumulative effect of the use of many lights over time that consumes a substantial amount of energy. Electricity comprises a substantial portion of the actual cost of lighting, which can be broken down into bulbs, electricity, fixtures, and wiring. A feasible strategy reduces CO_2 emissions by 29, 000 tons at $16 per ton. Residential lighting has the potential to reduce CO_2 emissions by 230,000 tons at $12 per ton. The amount of electricity that a bulb uses is largely dependent on the bulb type. The most common in the residential sector is the incandescent bulb. Roughly 80 percent of indoor residential lighting is made up of incandescent lights, the cost of which is fairly inexpensive at roughly $40. A 75-watt incandescent bulb has an estimated life of 750 hours. The average residential light is used roughly 3 hours every day, so bulb life is estimated at 9 months.

The actual cost of lighting includes fixtures, wiring, and electricity. Under the assumption that wiring and fixtures are interchangeable between incandescent lighting and fluorescent lighting, the major variables remain the bulb cost and electricity. Although the fluorescent bulb costs more than the incandescent bulb, the cost of replacing incandescent bulbs and the additional electricity needed to use such bulbs is higher that the cost of the costs associated with the life-cycle cost of a fluorescent bulb. A fluorescent bulb pays for itself in just over 2 years. Comparing the cost of an incandescent bulb over the lifetime of the fluorescent bulb illustrates that the fluorescent bulb costs $34 less than the incandescent bulb.

A bulb used to a lesser extent is the compact fluorescent. (The average home pays 0.44 cents an hour to use a 75-watt bulb, assuming that a kWh costs 5.88 cents.) Approximately 20 percent of indoor residential lighting consists of fluorescent bulbs. The cost of a 22-watt compact fluorescent bulb is assumed to be $10, with an estimated life span of over 9 years, assuming use comparable to an incandescent bulb. It would cost the average home 0.13 cents an hour to use, at 5.88 cents per kWh.

Differences of GHG emissions resulting from incandescent bulbs and fluorescent bulbs are substantial. Fluorescent bulbs use 70 percent less electricity than incandescent bulbs. This reduction of energy directly corresponds to a reduction of GHG emissions.

Building Code Improvements

Building codes set the minium standards to which homes must be constructed. The purpose of these codes is to standardize buildings to ensure that buildings meet a minimum level of safety, public health, energy efficiency, conformity with the public infrastructure, and other purposes designed to promote the public good. In 1978 the State of Utah passed an amendment to the Utah Uniform Building Standards Act that changed the Utah building standards to match those in the Model Code for Energy Conservation, a nationally recognized standard. Since its enactment, the Utah Uniform Building Standards Act has been based on models designed and endorsed by national professional organizations. Currently the Utah residential code is based on the 1995 Model Energy Code. Although this is not the most current Model Energy Code, it is still relatively up to date.

Energy Star® Homes

Energy Star® Homes is a program that works with home builders to provide homes that are at 30 percent more efficient than homes built to meet the minimum requirement of the Model Energy Code. The Energy Star®Homes program rates three major areas: heating, cooling, and water heating. These areas make up about 37 percent of Utah's electricity use in the residential sector.

As an incentive to encourage builders to incorporate better building practices, the Energy Star® Homes program certifies that the home exceeds the Model Energy Code by at least 30 percent. This program is not designed to address the size of the home but a home's relative energy efficiency level compared to those in similar environments. This label may act as an additional incentive when purchasing the home and may lead to preferred mortgage finances from lending institutions since the label serves as a verification of lower than average energy bills. Exceeding the Model Energy Code by 30 percent will also cut heating and air conditioning costs in proportion to a decline in energy use. The label distinguishes energy-efficient homes in the market place.

It is estimated that the average Energy Star® Home costs somewhere within the range of $200 to $500 more than a home that only meets the minium standards of the Model Energy Code. However, it is important to note that some home builders have found that energy efficiency does not necessarily cost more. A building firm in Utah, for example, found that by eliminating some waste within the construction process it was able to meet Energy Star® requirements without increasing building costs. Even assuming the initial estimate cost of $500, the average home owner would soon save considerably each month. Within a few years, this energy-efficiency improvement pays for itself. The EPA estimates that over the life of a 30-year mortgage, a Energy Star® home owner may save more than $50,000 through reduced monthly utility bills. Savings occurs when the increase in a monthly mortgage is less than the decrease in the monthly utility bill.

Weatherization

Weatherization broadly includes various home improvement and maintenance projects that improve energy efficiency. Examples of weatherization include high-efficiency windows and insulation. This strategy leads to substantial reductions in residential sector GHG emissions through direct reductions in electric power and natural gas consumption by households.

Green Power Marketing

Green power is electricity generated by using resources with a minimal effect on the environment. Energy made from wind, solar, and geothermal resources have the most benign effect on the environment. Other resources such as hydro, biomass, and natural gas have more impact than the least harmful resources but less impact than other sources including coal, nuclear, and oil. *Green,* however, is a matter of degree. For the purpose of this strategy, *Green power* includes only wind, solar, and geothermal resources. A feasible strategy reduces CO_2 emissions 62,000 tons at $21 per ton. Green power marketing has the potential to reduce CO_2 emissions by 124,000 tons at $18 per ton.

Green pricing refers to selling Green power within a regulated environment, presumably at a price above that of the current rate. The rationale behind such an option in a regulated environment is that it gives consumers who prefer to use Green power the option to do so. The benefit of such an option spills beyond that gained by the electricity users who choose to participate in such a program. The introduction of new renewable resources helps diversify the system, reduces environmental degradation, and increases system capacity.

Beyond satisfying consumer preferences, Green pricing also provides a substantial potential to reduce GHG emissions. Of all the sectors, experience from other states shows that the residential sector is most likely to participate followed by the commercial sector and the industrial sector. By 2010 it is feasible that 5 percent of the consumers in the residential sector, 3 percent in the commercial sector and 2 percent in the industrial sector would likely participate in such a program, given an aggressive marketing campaign.

Net Metering

Net metering provides an additional strategy to provide more electric power generation from renewable sources. It uses a single meter to measure the difference between the total generation and total consumption of electricity by customers with small generating facilities by allowing the meter to turn backward. Net metering can increase the economic value of small renewable energy technologies for customers. It allows the customers to use the utility grid to "bank" their energy: producing electricity at one time and consuming it at another time. This form of energy exchange is particularly ideal for renewable energy technologies. Small-scale electricity generated from renewable energy sources is sold back to the electric utility at retail prices rather than cost. A feasible strategy reduces CO_2 emissions by 46,000 tons at $287 per ton. Net metering has the potential to reduce CO_2 emissions by 87,000 tons at $287 per ton.

C. Residential Sector Summary

Table 5-1 presents residential mitigation strategies ranked according to cost. Across the feasible and potential categories, weatherization, and lighting are the most cost-effective measures. Utility-sponsored programs such as Green pricing are relatively inexpensive, while net metering, which entails consumer investment, is the highest-cost strategy in the residential sector.

Table 5-1. Summary of Residential Sector Strategies

	CO_2 Quantity (in thousand tons)		Cost per ton	
	Feasible	**Potential**	**Feasible**	**Potential**
Weatherization	55	388	$4	$3
Lighting	29	230	$16	$12
Green marketing	62	124	$21	$18
Convert water heaters	10	64	$30	$20
Premium refrigerators	9	150	$44	$44
Net metering	43	87	$287	$287
Total	**209**	**1,043**	**$73**	**$38**

III. Commercial Sector

A. Introduction

Utah's commercial sector includes the infrastructure that provides for much of Utah's public life. Schools, churches, government buildings, restaurants, office buildings, stores, and hospitals are several types of structures that fall into this important sector. These are the buildings that define our cities and towns, providing the necessary services that enhance our quality of life.

In terms of contribution to Utah's GHG emissions, these buildings are quite significant. Typically large in size, each building consumes large amounts of energy. Yet an economy of scale tends to favor large structures, since the cost per square foot of conservation decreases as the size of a structure increases. As a result, most commercial building owners can readily pay for energy efficiency improvements through the savings realized on their energy bills.

Utah's commercial sector is forecast to release 14.1 million tons of CO_2 by the year 2010, up from 7.8 million tons of CO_2 in 1990. This represents a total increase of 80.8 percent, or about 4.0 percent a year. The commercial sector accounted for 18.1 percent of Utah's energy-related GHG emissions in 1990 and increased to 19.1 percent in 1998. With the rapid growth of the commercial sector in Utah, it should account for 20.5 percent of CO_2 in 2010.

B. Selected Strategies

Lighting

Lighting results in about 35 percent of CO_2 emissions in the commercial sector. This simple fact, along with an impressive variety of energy-efficient lighting technologies, introduces significant opportunities for substantial energy savings. Federal agencies such as the DOE and EPA have long recognized the potential for energy-efficiency improvements in lighting and have sponsored numerous programs to encourage more efficient lighting.

Several factors must be considered when evaluating lighting needs and energy consumption. These include: 1) total floor space; 2) percent of the floor space lighted during usual operating hours; 3) percent of floor space lighted during off hours; 4) percent of floor space lighted during usual operating hours that was lighted by each of several lamp types; 5) operating hours per week; 6) principal activity taking place in the building; and 7) the presence of various lighting conservation features already in place.

High-Efficiency Lighting Retrofit

This strategy replaces all existing magnetic ballasts and T12 F34 fluorescent lamps with electronic ballasts and T8 F32 lamps. New ballasts should have a high power factor and low harmonics. The T8 lamps should be tri-phosphor with average design lumens in excess of 2,550 and a color rendering index of 75 or higher.

Another strategy is to replace incandescent lamps with compact fluorescent lamps (CFLs). There are now CFLs available to fit almost any incandescent fixture. A screw-in ballast adapter can be used or the fixture can be retrofit with a built-in ballast. There are now dimmable units as well. Compact fluorescent lamps have a projected life span 10-15 times longer than incandescent lamps, which makes operation and maintenance savings significant. The payback for a retrofit of fixtures operated for about 12 hours per day is less than 6 months.

High bay or outdoor lighting systems that use incandescent, mercury vapor, or fluorescent lamps can be replaced with high-efficiency High Intensity Discharge (HID) systems using metal halide, high-pressure sodium, or low-pressure sodium fixtures. Exit lights can be retrofited with LED units. These are more expensive but are very cost effective given their extremely long life and low energy requirements (on the order of 2 watts).

A feasible strategy results in a 142,000 ton reduction at $20 per ton. Lighting has the potential to reduce CO_2 emissions 899,000 tons at $15 per ton.

Lighting Controls

Lighting controls are an additional commercial strategy. At a minimum, occupancy sensor controls should be installed in irregularly used areas such as restrooms and in common rooms such as break rooms. These are spaces typically left vacant for extended periods with the lights left on. Lighting controls result in a feasible reduction of 38,00 tons of CO_2 at $24 per ton. Lighting controls have the potential to reduce CO_2 emissions 284,000 tons at $17 per ton.

Occupancy sensors can be infrared or ultrasonic as appropriate for the space. Infrared sensors detect the presence of a person by body heat and operate well in areas with obstructions such as restrooms. Ultrasonic sensors which detect movement are well suited for open areas such as corridors and conference rooms. Both are available in combination sensor/switch plate units or ceiling mounted units and the delay prior to unoccupied off switching is adjustable. Typical electricity savings from occupancy sensors in break rooms is 45-65 percent and 30-75 percent in restrooms.

Ideally, all spaces should have occupancy sensor control. Other options include time-of-day controls that schedule lighting for expected occupancy hours. Override switches allow temporary lighting for a specified period during scheduled unoccupied hours.

Controls are also available for use with dimmable ballasts that allow dimming of light fixtures in spaces where daylight is available.

Heating, Ventilation, and Air Conditioning (HVAC)

Larger commercial buildings differ from residential and smaller commercial buildings both in size and complexity. Larger commercial buildings tend to have more sophisticated heating and cooling systems and require much more active ventilation systems in order to maintain air quality. Due to scale and diversity of needs, a large degree of sophistication is introduced to control air temperature and air quality. A large building might require cooling a computer room, ventilating a machine room, and heating business offices. This diversity of needs is served in many large commercial buildings by a computerized system that regulates heating, ventilation, and air conditioning (HVAC).

Due to the complexity of these systems, it is difficult to generalize about potential energy savings. Before Congress dissolved the Office of Technology Assessment (OTA), the office published a report entitled *Building Energy Efficiency*. In this report several categorical improvements are mentioned, including the following:

- improving the efficiency of energy-using devices (e.g., using a higher-efficiency chiller);
- improving the design of the overall system (e.g., routing and designing ducts to minimize losses);
- switching to different systems (e.g., using a heat pump rather than electric resistance heating);
- improving system controls (e.g., using outside air for cooling when appropriate);
- improving maintenance (e.g., changing filters as needed); and
- reducing demand for services provided by the system (e.g., installing more efficient lights to reduce the need for space cooling).

HVAC Automatic Control System

A variety of control systems are capable of monitoring and controlling HVAC equipment. The commercial sector HVAC automatic control strategy is shown in 5-2. They result in a feasible reduction of 25,000 tons of CO_2 $45 per ton. HVAC automatic control systems have the potential to reduce CO_2 emissions 126,000 tons at $35 per ton.

Table 5-2. Summary of Commercial Sector Strategies

	Quantity (in thousand tons)		Cost per ton	
	Feasible	Potential	Feasible	Potential
Building Commissioning	98	731	$3	$1
Variable-Speed Drive				
Motors	25	172	$14	$11
Lighting Controls	38	284	$24	$17
Lighting	142	899	$20	$15
Plug Load	42	72	$2	$2
HVAC	25	126	$45	$35
Net Metering	57	115	$191	$191
Green Marketing	49	98	$173	$137
Total	**458**	**2,498**	**$61**	**$27**

A given HVAC system's complexity dictates the level of controls necessary to effectively manage the system. For simple heating and cooling, all that may be required are time of day controls with night time temperature set back. More complex central heating and cooling plants should utilize dynamic optimal control sequences. This allows maximized performance through fan scheduling, temperature setback, optimum start/stop logic, discriminator-based discharge air temperature, integrated chilled water and discharge air temperature control, condensing water temperature adjustment, boiler control based on outside air temperature, CO_2-based ventilation control, occupancy sensor controlled air supply, static pressure reset or terminal regulated volume control on variable volume fans, variable speed pump control, economizer control, and damper control.

Building Commissioning/Recommissioning

Commissioning is the process of inspecting and testing a building to ensure that all systems are operating as intended. This process should be completed on new construction and repeated (recommissioning) periodically over a building's life. The commercial building commissioning/ recommissioning strategy is shown in Table 5-2. It results in a feasible reduction of 98,000 tons of CO_2 at $3 per ton. Building commissioning/recommissioning has the potential to reduce CO_2

emissions 731,000 tons at $1 per ton.

The commissioning process includes verification of proper performance regarding equipment and installation, controls, operations, and default settings. Tests should verify temperatures, air pressures, damper and valve operations, and control sequences. Switches are checked to confirm they are in the intended position; mechanical linkages are checked for proper connection and movement; and heating, cooling, and air flow capacities are confirmed. Each system component is checked to verify design performance. Occupancy sensors are monitored as well as light and humidity levels.

Fire, safety, and security systems are tested to ensure proper air pressure differentials in the case of fire, proper emergency lighting and alarms, proper startup of emergency power systems, and proper lockdown of facilities.

Variable Speed Drives

Variable speed drives should be installed on pump and fan motors allowing variable air volume and variable flow while eliminating bypass waste. Only the amount of air, water, and glycol necessary to meet the demand is circulated. This allows motors to operate at lower loads, thereby reducing electrical energy consumption. This strategy results in a feasible reduction of 25,000 tons of CO_2 at $4 per ton. Variable speed drive motors have the potential to reduce CO_2 emissions 172,000 tons at $11 per ton.

Commercial Refrigeration

Commercial refrigeration consists of four major groups: display refrigerators, storage refrigerators, processing refrigerators, and mechanical refrigeration machines. Within each group of refrigerators, many different refrigerator models exist. Depending on the use of the refrigerator and the specific type of model used, different strategies exist for improving efficiency.

Refrigeration accounts for seven percent of electricity used within the commercial sector. Some of the factors that determine a refrigerator's efficiency include desired refrigerated temperature, the amount of time the refrigerator is open, the amount of heat to be moved, the degree to which temperature outside the refrigerator influence the performance of the refrigerator, the quality and type of material that makes up the refrigerator, the energy efficiency of its parts, and the size and design of the refrigerator.

Refrigerator improvements can offer impressive energy savings. Due to the size of savings involved, many of these measures pay for themselves fairly quickly. It is estimated that the energy efficiency of most refrigerators could improve by 25 percent.

Public Sector Buildings

Public sector buildings, due to the economy of scale in implementing energy efficiency, can offer tremendous energy savings. In Utah, during the 1999 legislative session, the Quality Growth Act outlined a plan to utilize savings from such projects. A portion of the savings is returned to the agency directly benefitting from the savings, and a portion is funneled into the LeRay McAllister Critical Land Conservation Fund, which is used to purchase open space for preservation.

The OTA has identified barriers for implementation of cost-effective technologies that are commercially available. These include the following:

- There is often a separation between those who purchase energy-using equipment and those who pay to operate the equipment, which undermines existing incentives for efficiency. For example, one-third of housing, and one-quarter of commercial building floor space, is leased or rented rather than owned.
- Decisions on purchasing energy-using equipment require comparisons across many attributes, such as cost, performance, appearance, features, and convenience. These other attributes often overshadow energy efficiency considerations.
- Individuals tend to minimize risk in purchasing expensive equipment. The habit of purchasing "tried and true" technologies frequently works against the adoption of newer and more efficient technologies. In short, very few decision makers pursue the goal of minimizing life-cycle costs (the sum of capital and operating costs over the life of the equipment), which energy-efficient technologies achieve.
- When trading off cost and energy savings, consumers will not invest in efficiency unless it offers very short payback periods–less than 2 years for home appliances, for example. However, personal financial investments generally offer much lower returns.
- Energy cost is relatively low (about 1 percent of salary cost in a typical office, for example), so those concerned with cost reduction often focus elsewhere.
- Energy efficiency is often misperceived as requiring discomfort or sacrifice, limiting its appeal.

Due to its size and stability, the government is often better prepared than private and commercial interests to undertake long-term energy efficiency improvements. As a result, this increased penetration rate translates into increased GHG reductions from the portion of the commercial sector or that the public sector represents.

Green Marketing

Beyond satisfying consumer preferences, Green pricing also provides a substantial potential to reduce GHG emissions. Of all the sectors, experience from other states shows that the residential sector is most likely to participate followed by the commercial sector and the industrial sector. By 2010 it is feasible that 5 percent of the consumers in the residential sector and 2 or 3 percent in the commercial and industrial sectors would likely participate in such a program, given an aggressive marketing campaign. This strategy could result in a feasible reduction of 49,000 tons of CO_2 at \$173 per ton. Green marketing has the potential to reduce CO_2 emissions 98,000 tons at \$137 per ton.

Net Metering

The commercial sector net metering strategy is shown in Table 5-2. It offers a feasible strategy that could result in a reduction of 57,000 tons of CO_2 at \$191 per ton. Net metering has the potential to reduce CO_2 emissions 115,000 tons at \$191 per ton.

C. Commercial Sector Summary

For the commercial sector, the least-cost strategies include investments in building commissioning, new appliances such as lighting, and process controls such as motors. In parallel with the residential sector, the highest cost commercial reduction measures include utility-sponsored projects such as DSM, net metering, and Green pricing.

The Utah Department of Natural Resources Building

From its orientation to the selection of lighting and mechanical systems, the new Utah Department of Natural Resources (DNR) building is a $11.9-million, 105,000-square foot facility constructed using a *whole-building* approach to ensure the entire building works as a single system to minimize energy use. The result is a building designed to reduce energy consumption by 42 percent and save $50,000 per year in energy costs.

A properly oriented building with a large aspect ratio minimizes solar-heat gain while taking maximum advantage of abundant natural daylight. The new DNR building's north and south exterior walls are long, allowing more of the interior to be illuminated with the sun's natural light. The building's east and west exterior walls are narrow to minimize unwanted solar gain during Utah's hot summer months. This feature reduces costs.

A combination of day lighting design techniques illuminates interior spaces and corridors with free sunlight. Light shelves on the south exterior wall reflect sunlight deep into the building's interior, more than doubling the area receiving natural light. Light shelves also serve to shade south facing windows from the sun's direct glare, reducing the building's cooling load and increasing employee comfort. Clerestory windows on side walls allow sunlight to be shared with interior offices, conference rooms, and hallways. High-performance, low-e glass allows 70 percent of visible light into the building while blocking out other light waves that create unwanted heat. Energy-efficient lighting design of the DNR building calls for two types of light fixtures. T-8 fluorescent ceiling lamps and electronic ballasts provide a better quality light and use about half the energy of standard fluorescent fixtures. Indirect lighting fixtures bounce light off ceilings and walls to provide more uniform, natural light throughout the building. Used in conjunction with task lights, indirect lighting saves electricity by requiring less than half the light of standard recessed-ceiling fixtures to illuminate a comparable space. LED exit signs not only use less energy but require less maintenance and, most importantly, are more visible in a smoke-filled room.

Lighting controls installed in the new building save electricity by providing light only when needed. Occupancy sensors automatically turns off lights when an office is not in use. Dimming ballasts save electricity by controlling the level of indirect light fixtures according to amount of natural light available to the building interior. Dimming ballasts automatically turn up light levels on cloudy days and down on sunny days.

Utah DNR takes advantage of Utah's hot, dry climate by using inexpensive, energy saving direct/indirect evaporative cooling technology in the building. Expensive refrigerated air from mechanical chillers is needed only on the hottest days of the year. To operate the cooling and air exchange systems, the DNR uses 1) motors that require 2-3% less electricity; and 2) variable speed drivers that make fan motors operate at the minimum speed required to perform the job. Conventional ventilation systems use less efficient motors that operate at maximum power. Wise-water landscaping and use of recycled materials also emphasize the importance placed on resource conservation. [OERP "Energy-Efficient Design."]

IV. Industrial Sector

A. Introduction

The Utah industrial sector spans a wide range of manufacturing and non-manufacturing activities. While capital-intensive, resource-based industries have figured prominently in the state's economic history, today's Utah economy is increasingly characterized by high technology firms that require less energy per unit output.

Table 5-3 details the energy consumption patterns of Utah's most significant manufacturing and non-manufacturing industries by Standard Industrial Classification (SIC) code. Industries generally consume primary energy in the form of fossil fuels for process or heating applications. Secondary energy, in the form of electricity, is used for a wide variety of processes such as conveyance, heating, and cooling. Other important energy uses include space conditioning (heating and cooling), ventilation, and water heating. Both energy forms are converted into trillion Btus (TBtus) for convenience of expression.

By SIC category, Petroleum and Coal Products, Chemical and Allied Products, Paper and Allied Products, and the Primary Metal Industries are the largest consumers of energy in TBtus in the Industrial sector.

Utah's industrial sector is forecast to release 23.3 million tons of CO_2 by the year 2010, up from 15.3 million in 1990. This represents a total increase of roughly 52.3 percent, or about 2.6 percent per year. The industrial sector accounted for approximately 38 percent of all CO_2 emissions in 1990 and is projected to account for 32 percent of the expected 69.9 million tons in 2010.

Table 5-3. Utah Energy Consumption by SIC Code

SIC	Industry	Electricity Consumption (million kWh)	Electricity Consumption (TBtu)	Non-Electric Consumption (TBtu)	Total Energy (TBtu)
20	Food and Kindred Products	394.43	1.35	7.01	8.35
22	Textile Mill Products	221.78	0.76	1.41	2.17
24	Lumber and Wood Products	134.89	0.46	2.98	3.44
25	Furniture and Fixtures	44.81	0.15	0.33	0.48
26	Paper and Allied Products	445.26	1.52	17.14	18.66
27	Printing and Publishing	118.38	0.40	0.38	0.78
28	Chemical and Allied Products	1,036.88	3.54	33.76	37.30
29	Petroleum and Coal Products	240.99	0.82	43.55	44.37
30	Rubber and Misc. Plastics Products	297.49	1.02	0.99	2.01
32	Stone, Clay, and Glass Products	244.92	0.84	5.77	6.61
33	Primary Metal Industries	982.37	3.35	13.88	17.23
34	Fabricated Metal Products	229.97	0.79	1.78	2.57
35	Industrial Machinery and Equipment	217.85	0.74	0.98	1.72
36	Electronic and other Electronic Equipment	225.41	0.77	0.93	1.70
37	Transportation Equipment	263.66	0.90	1.64	2.54
38	Instruments and Related Products	91.73	0.31	0.44	0.75
					150.68

B. Selected Strategies

The Utah industrial sector offers several promising opportunities for energy-efficiency improvements. Because of the wide variation in production processes and in energy use between firms in a given industrial category (e.g. steel or refineries) and across different industries, it is relatively difficult to generalize about energy efficiency opportunities.

Across all industries and fuels, industrial process heating accounts for the greatest fraction of CO_2 emissions (41 percent), followed closely by general processes including conveyance, air compression, and motor-related applications (34 percent). Space heating represents 10 percent. Water heating and process cooling each represent 3 percent of the total. Collectively, these five processes account for 81 percent of all CO_2 emissions in the industrial sector. Each process will be analyzed in turn to identify energy-efficiency opportunities.

Motors

The primary strategy with respect to motors is to optimize motor system efficiency, particularly in pump systems, fan systems, and compressed air systems. System efficiency can be improved by reducing the overall load on the motor through improved process or system design, improving the match between component size and load requirements, use of speed control instead of throttling or bypass mechanisms, and better maintenance.

Once system efficiency has been optimized, motor retrofits should be made, including the downsizing of motors. It may be possible to downsize motors. All motor replacements should be of premium efficiency. The industrial sector HVAC motor strategy could result in a feasible reduction of 82,000 tons of CO_2 at a cost of $26 per ton.

Table 5-4. Motor System Energy Use by Major Industry Group

Industry Categories	Net Electric Demand (million kWh)	Motor System Energy (million kWh)	Motor System Energy as % of Total Electricity
Manufacturing	**917834**	**541203**	**59%**
Process Industries (SICs 20, 21, 22, 24, 26-32)	590956	419587	71%
Metal Production (SIC 33)	152740	46093	30%
Non-Metals Fabrication (SICs 23, 25, 36, 38-39)	106107	50031	47%
Metals Fabrication (SICs 34, 35, 37)	68031	25492	37%
Non-Manufacturing	**167563**	**137,902**	**82%**
Agricultural Production (SICs 01, 02)	32970	13452	41%
Mining (SICs 10, 12, 14)	44027	39932	90%
Oil and Gas Extraction (SIC 13)	33038	29866	90%
Water Supply, Sewage, Irrigation (SICs 494, 4952, 4971)	57528	54652	95%
Total All Industrial	**1,085,397**	**679,105**	**62%**

Industrial Process

In 1994, electric motor-driven systems used in industrial processes consumed 679 billion kWh or 23 percent of all electricity sold in the United States. These machines comprise by far the largest single category of electricity end use in the national economy. According to the EPA's Motor Challenge Program, industrial motor energy use could be reduced by 11 to 18 percent if all cost-effective applications of mature and proven energy efficiency technologies and practices were adopted. Collectively, these technologies could result in energy savings of 75 to 122 billion kWh with an expenditure of between $11 to $17 billion. Potential savings in the non-manufacturing sectors could reach as high as 14 billion kWh at the same cost per kW installed.

There are two basic categories of motor system energy efficiency measures: motor efficiency upgrades and system efficiency measures. The former improve the energy efficiency of the motor driving a particular machine or group of machines. The latter improve the efficiency of a machine or group of machines as a whole. System efficiency can be improved by reducing the overall load on the motor through improved process or system design, improving the match between component size and load requirements, use of speed control instead of throttling or bypass mechanisms, and better maintenance, to name just a few of the engineering strategies available.

According to Motor Challenge, motor efficiency improvements alone can lower energy by 2.9 percent. Improved methods of rewinding can account for another 1 percent consumption. Energy

Table 5-5. Industrial Electricity Energy and Emissions Savings

Efficiency Strategy	Cost/kWh (cents)	Energy Savings(MW)	Cost/Ton of CO_2 mitigated (dollars)
Equip air compressors with unloading kites	1.4		$39.00
Install unloading valve and accumulator for hydraulic pumps	2.1	27	$5.99
Install efficient exhaust hoods	2.2	6.7	$62.77
Install electronic variable speed drive to better control motors	3	308	$8.56
Downsize pumps to better match loads (10 to 5 hp)	4	117	$11.42
Efficient fan motors	4.9	6.5	$140.65
Irrigation pumps	5.1	0.6	$144.90
Downsize motors to better match loads	6	24	$17.13
Install variable speed drive to replace throttling device to correct for pump over capacity	10	34	$28.55
Install an electronic variable speed drive to better control motors subject to varying load conditions (51 to 125 hp)	14	111	$39.97
Install an electronic variable speed drive to better control motors subject to varying load conditions (21 to 50 hp)	15	44	$42.82
Replace inlet vanes on air drying fans with a variable speed motor	18	6	$51.38
Install an electronic variable speed drive to better control motors subject subject to varying loads (5 to 20 hp)	18	31	51.38
Install oversize piping to lower	33	64	94.2

Source: Northwest Power Planning Council, Conservation Resource Advisory Committee, and PacifiCorp's RAMPP 5.

savings from system-wide efficiency improvements can gain another 9 percent. Overall, these improvements could gain as much as 13 percent energy savings.

Table 5-4 presents motor system energy use by major industry group for the nation as a whole. The far right column shows estimated savings which are broadly applicable to Utah.

As indicated in the table, the manufacturing sector accounts for 85 percent of the nation's total industrial electricity demand. In terms of motor system energy, manufacturing accounts for 80 percent of the total. In this latter category, process industries represent 62 percent of total demand. The non-manufacturing sector's demand for motor system energy is 20 percent of the total with water supply, sewage and irrigation accounting for the largest percentage use.

In Utah, electricity is the primary form of energy used in industrial processes. Together with transmission and distribution (T&D) losses, electricity accounts for 83% of all energy consumed in the industrial sector. The primary strategy with respect to motors is to optimize motor system efficiency, particularly in pump systems, fan systems, and compressed air systems. System efficiency can be improved by reducing the overall load on the motor through improved process or system design, improving the match between component size and load requirements, use of speed control instead of throttling or bypass mechanisms, and better maintenance.

Table 5-5 provides a wide array of electricity efficiency strategies for industrial processes listed by measure cost. Industrial processes collectively account for 6,147 tons of CO_2, ranked second behind process heating. Note that costs are levelized over 15 years and do not account for accrued energy savings. Capacity savings (MW) are cumulative over the 15 year horizon.

Space Conditioning

Space conditioning refers to HVAC applications for the heating and cooling of work spaces. The following measures include both building shell improvements and HVAC equipment. In this category, window and solar film are by far the least-cost strategies (see Table 5-6).

Process Cooling

Table 5-6. Industrial Electricity Energy and Emissions Savings

Efficiency Strategy	Cost/kWh (cents)	Energy Savings (MW)	Cost/Ton of CO_2 mitigated (dollars)
Low E Windows	0.9	19	28
Solar film	3.8	8.6	108.7
Economizers	6.2	5.9	177
Refrigeration Pumps	3.02	3.6	86.1

Source: Northwest Power Planning Council, Conservation Resource Advisory Committee, and PacifiCorp's RAMPP 5.

Process cooling refers to low temperature modification of production processes. Refrigeration is the primary application. Pumping costs are offered as the sole measure for which cost and savings have been estimated.

Process Heating and Water Heating

Process and water heating accounted for 44 percent of 1998 industrial emissions of CO_2. In terms of the fuel used, coal accounted for 50 percent of all emissions, followed by natural gas at roughly 25 percent. Distillate and other fuels largely comprised the remainder with minimal contributions from electricity. For water heating applications, natural gas and distillate fuel accounted for more than three-fourths of all CO_2 produced. Electricity and associated losses made up 14 percent of the total.

The opportunities for emissions mitigation in these two categories are relatively limited since both applications generally require the direct use of high-btu fossil fuels for which there are relatively few substitutes. Precisely because virtually all industries require electricity in addition to thermal energy, combined heat and power (CHP) projects have become popular strategies for reducing energy consumption.

CHP refers to the sequential production of thermal and electric energy from a single fuel source. In the CHP process, heat is recovered that would normally be lost in the production of one form of energy. For example, in the case of an engine configured to produce electricity, heat could be recovered from the engine exhaust and used for processes or water heating, depending in part on the exhaust temperature.

The recycling of waste heat differentiates CHP facilities from central station electric facilities. The overall fuel utilization efficiency of CHP plants is typically 70-80 percent versus 35-40 percent for utility power plants. The basic components of any CHP plant include a prime mover, a generator, a waste heat recovery system, and operating control systems. Typically, CHP systems are configured around three basic types of generators: 1) steam turbines; 2) combustion gas turbines; and 3) internal combustion engines. Table 5-9 shows a comparison of energy balances for CHP and central station facilities.

As apparent from the table, CHP systems succeed in recovering all losses from the condenser and 12 percent from exhaust stacks. Radiated losses, however, are not recovered.

Table 5-7. Energy Balance: CHP Versus Central Station

Energy Balance Stage	Without Heat Recovery	With Heat Recovery
Electrical Energy Output	33%	33%
Condenser Losses	30%	0%
Condenser Recovery	0%	30%
Exhaust Stack Recovery	0%	12%
Exhaust Stack Losses	30%	18%
Radiated Losses	7%	7%
Total	**100%**	**100%**

A representative CHP project for Utah industrial customers would likely consist of a facility rated at less than12 MW with a capacity factor of approximately 80%. These systems are primarily internal combustion engines or combustion turbines, generally using natural gas for fuel. Such systems reduce energy purchases and may also increase the reliability of electric power delivery. In many cases, industries benefit from sell back tariffs which compel investor-owned or public utilities to purchase excess electricity. Historically, these sell back tariffs have figured prominently in the decision to develop CHP projects.

For a Utah case study, consider a 4 MW CHP facility. The heat rate (Btu/kWh) for an internal combustion engine of this capacity is on the order of 4,250, which compares with 11,390 for a typical coal-fired central station facility. Fixed and variable O&M costs amount to $563,443 and variable fuel costs are $280,000 rising at a real rate of 2.4% annually. Three levels of capacity factor are assumed: 70, 80, and 90 percent. Table 5-10 details the tons of CO_2 reduced in 2010 and the annualized costs per ton for this example.

Table 5-8. Emissions Reduction and Costs for Combined Heat and Power

	Low	Feasible or Best Estimate	Potential or High
Tons CO_2 reduced in 2010	81,449	93,085	104,721
Annualized $/ton CO_2	14	12	11

Steam System Optimization

This strategy seeks to optimize steam system performance through improved operation and maintenance procedures. The industrial sector steam system optimization strategy is shown in Table 5-3. It results in a feasible reduction of 83,000 tons of CO_2 at $13 per ton. Steam system optimization has the potential to reduce CO_2 emissions 166,000 tons at $12 per ton.

Several aspects of the industrial steam system operation and performance need to be considered. A steam balance needs to be developed and actual operating conditions and system requirements for both winter and summer operating conditions must be considered. Steam excess or deficit must also be balanced. Optimization includes integrating plant operations to avoid steam venting and cycling operations with high demand.

Eliminating excess steam is a key aspect of steam system optimization. Opportunities include shutting down turbines, checking for leaking valves, examining turbines, upgrading turbines, and varying header.

High-Efficiency Lighting Retrofit

This strategy seeks to replace all existing magnetic ballasts and T12 F34 fluorescent lamps with electronic ballasts and T8 F32 lamps. New ballasts should have a high power factor and low harmonics. The T8 lamps should be tri-phosphor with average design lumens in excess of 2,550 and a color rendering index of 75 or higher. The industrial sector lighting retrofit strategy is shown in summary (Table 5-11). It results in a feasible reduction of 59,000 tons of CO_2 at $6 per ton. A high-efficiency lighting retrofit strategy has the potential to reduce CO_2 emissions 94,000 tons at $5 per ton.

Wherever feasible, incandescent lamps should be replaced with compact fluorescent lamps (CFLs). There are now CFLs available to fit in almost any incandescent fixture. A screw-in ballast adapter can be used or the fixture can be retrofit with a built-in ballast. There are now dimmable units as well. Compact fluorescent lamps have a projected life span that is 10-15 times longer than incandescent lamps making operation and maintenance savings significant. The payback on retrofits of fixtures operated about 12 hours per day is less than 6 months.

High bay or outdoor lighting systems that use incandescent, mercury vapor, or fluorescent lamps may be replaced with high-efficiency High Intensity Discharge (HID) systems using metal halide, high pressure sodium, or low pressure sodium fixtures. Exit lights should be retrofit with LED units. These are more expensive but are very cost effective given their extremely long life and low energy requirements (on the order of two watts).

C. Industrial Sector Summary

The least-cost reduction strategies in the industrial sector include steam system optimization and process improvements. Utility-sponsored programs are again ranked among the highest-cost measures. Additional potential for reduction may occur with large-scale cogeneration.

Table 5-9. Summary of Industrial Sector Strategies

	Quantity		Cost per ton	
	Feasible	**Potential**	**Feasible**	**Potential**
High-Efficiency Lighting Retrofit	59	94	$6	$5
Steam System Optimization	83	166	$13	$12
Motors (HVAC)	82	155	$26	$23
Net Metering	83	166	$48	$48
Green Marketing	33	66	$279	$221
Total	340	646	$49	$47

V. Transportation Sector

A. Introduction

In modern history, few developments have had as dramatic an impact on our way of life as transportation. Innovations such as rail, auto, and air transport have made the world smaller while expanding the marketplace. Today we visit destinations that past generations could only imagine and shop for goods from thousands of miles away.

These innovations, however, have not come without costs, some of which are quite high. As any commuter who has sat in congested traffic can attest, many of the current modes of transportation all too frequently fail to save us time – our most irrevocable resource – and considerably degrade our environment. Exhaust from vehicles makes a significant contribution to Utah's GHG emissions. In fact, burning just *one gallon* of gasoline results in approximately 20 pounds of CO_2.

Strategies to reduce transportation-related emissions can be separated into two categories. The first involves strategies designed to reduce vehicle miles traveled (VMTs). One strategy, for example, involves increasing the cost of transportation which tends to reduce the demand for such transportation. A related strategy turns on decreasing the need for travel. Increased telecommuting is an example of an action that can reduce or eliminate the original need for transportation. Less energy-intensive strategies such as car pooling, the designation of high-occupancy vehicles (HOV) lanes, and larger public works projects such as mass transit can also lead to significant reductions.

The second category of strategy relates to increasing fuel efficiency and reducing vehicle emissions. These strategies do not affect VMTs per se; rather, the strategies modify the amount of emissions that current and projected VMTs induce. Of course, reducing emissions per mile may not offset the increased number of vehicles due to population growth. One fuel efficiency strategy is to encourage people to drive vehicles that consume less fuel per mile than the vehicles they currently drive. This may be accomplished through several policy mechanisms including incentives for choosing fuel efficient vehicles or penalties for choosing inefficient vehicles. Another approach is to encourage practices that lead to higher efficiency per vehicle such as reducing speed. Other emission reduction strategies would present only minor inconveniences to drivers. One example is the maintenance of optimal tire pressure. Still another strategy includes alternative fuels which may provide efficiency gains without altering driver behavior. Switching fleets from gasoline to natural gas is a common practice that achieves this type of reduction.

B. Selected Strategies

Optimal Tire Inflation

Vehicles in motion face resistance which lowers their overall efficiency. The most obvious form is wind resistance which is a function of surface area and design. A less obvious form is frictional resistance which relates to a vehicle's motion in contact with the road surface. One simple way to reduce this form of resistance is to inflate tires to an optimal level since an under-inflated tire increases the surface area of a tire rolling on the road. A program to inflate tires to optimal levels is a potential mitigation strategy. Additional benefits accrue to the customer by reducing gasoline consumption, wear-and-tear on tires, and to a lesser extent the vehicle itself. By requiring optimal tire levels during annual safety and emissions testing or even as a routine part of regular maintenance, the state could reduce GHG emissions. As evident, the strategy represents an easy and inexpensive approach for the state to increase automobile fuel efficiency and reduce GHG emissions.

CAFE Standards and Feebates

In 1976 the federal government established Corporate Average Fuel Efficiency (CAFE) standards for automobiles and fleet vehicles. When CAFE standards were enacted, the average fuel efficiency for new vehicles was roughly 17 miles per gallon. The fuel efficiency levels increased dramatically by 10 miles per gallon in the next 10 years, where they have remained relatively constant. Current levels stand at about 28 miles per gallon. It is vital to note that sport utility vehicles (SUVs), which are classified as light duty trucks, are not covered by CAFE standards. SUVs now present roughly half of all new vehicles purchased, state and federal governments are increasingly interested in establishing standards for these vehicles.

Many supporters of more efficient vehicles maintain that increased CAFE standards would result in increased fuel efficiency. The US Office of Technology Assessment (OTA) reports that regulations could increase fuel efficiency by 20 percent. Automobile manufacturers can meet CAFE standards in a variety of ways. Regardless of the technology and design modifications, the CAFE standards set benchmarks that companies must meet or face fines for noncompliance by the U.S. Department of Transportation.

A feebate program is designed to help consumers internalize some of the costs (externalities) associated with inefficient vehicles. Feebates differ from CAFE standards by relying more on market forces rather than regulatory oversight powers.

Feebates establish a mileage target which starts out as the average fuel efficiency (expressed as average miles per gallon). A fee is charged to purchasers of inefficient vehicles and a rebate is given to those who purchase efficient vehicles. The fee or rebate is determined by the number of miles per gallon the vehicle consumes *below* or *above* the mileage target. The larger the feebate is for every mile per gallon above or below the mileage target, the greater the consumer's incentive to choose a more fuel-efficient vehicle. As manufacturers respond to the demand for more fuel efficient vehicles, the overall efficiency of the existing vehicle fleet increases. In addition, the change in demand will also correspond to a change in the feebate mileage target and hopefully prompt a new set of consumers to respond by buying even more fuel efficient vehicles.

While the federal government may institute such a program, the question remains whether or not states will be allowed to introduce feebates.

Alternative Fuel Vehicles

One approach to limiting GHG emissions from vehicles is to substitute less polluting fuels. Not surprisingly, different fuels emit different amounts of GHG per mile traveled. CO_2 production is a function of the *amount* and *type* of fuel burned whereas other types of emissions are responsive to changes in the *process* of burning fuels. Therefore, switching to fuels that emit less CO_2 is the key to this strategy.

A considerable amount of controversy surrounds the issue of emissions released during fuel production. Unlike tailpipe emissions, these are not as easy to calculate. For example, burning methanol and ethanol emits less CO_2 than gasoline per mile traveled. Yet, when production cycle emissions are included, these two fuels may actually generate higher overall CO_2 emissions than gasoline. Since calculating emissions during the production cycle involves many approximations and differs relative to specific processes, the actual emissions associated with these fuels remain the subject of debate among scientists.

Even after converting natural gas to a liquid form results in a CO_2 emissions reduction of about 20 and 12 percent per mile traveled compared with gasoline and diesel, respectively. This fuel is currently used in several Utah fleets, although currently the percentage of vehicles is small. Due to federal incentives and standards, it is quite commonplace for organizations with large vehicle fleets to dedicate a portion of their fleet to natural gas use.

Likewise, switching to liquefied petroleum gas (LPG) would also result in a 18 percent reduction in CO_2 emissions compared with gasoline. Currently, however, there is no readily available supply for large scale fleets. Other states have begun to introduce large numbers of LPG vehicles into the fleet. The California GHG report estimates that approximately 40,000 vehicles rely on LPG as a fuel source.

Conversions to hydrogen as a power source may result in substantial reductions. Hydrogen, a non-carbon-based fuel, emits practically no CO_2. Producing this fuel, on the other hand, does lead to some emissions. The net emissions from production and consumption of a hydrogen power source are thought to be roughly 40 percent less than gasoline per vehicle mile traveled. This fuel, though promising, is not commercially available.

Electric vehicles are also considered alternative fuel vehicles. However, it is difficult to approximate CO_2 emissions from these vehicles because the electricity may vary in composition; that is, electric vehicles powered by electricity from "Green" sources (e.g. wind, solar, and hydro) will produce less GHG emissions than from those vehicles powered by traditional electricity sources (e.g. coal and natural gas). An estimate from California shows that electric vehicles powered by electricity produced from a natural gas power plant might reduce emissions by about 20 to 30 percent.

Telecommuting

Telecommuting refers to those programs that allow public or private employees the opportunity to work in alternative locations to their primary place of work. Generally, telecommuting offers an employee the opportunity to work at or close to home in order to avoid or reduce burdensome commutes. Telecommuting typically requires office equipment such as a desk, chair, computer, fax machine, and/or telephone. Email and the internet are examples of technologies which will likely improve the prospects of telecommuting.

The benefits of telecommuting are not limited to trip reduction and related savings in GHG emissions. The practice also saves time, reduces vehicle wear-and-tear, eases road congestion, and saves on work space, parking, and other infrastructure costs. On a more subjective level, other benefits include increased contact with family members and potentially reduced child care costs. Additional benefits not readily measured include increased scheduling flexibility and less psychological stress. The percentage of employees in Utah who currently telecommute is relatively small. However, this is only a fraction of the potential number who could telecommute.

Enhanced I&M

Attention to the operation and maintenance of vehicles can greatly increase performance and fuel efficiency. One strategy is to expand and enhance inspection and maintenance (I&M) programs to identify those vehicles with the lowest engine efficiency. Owners of such vehicles could then choose between making repairs to improve efficiency to acceptable levels or removing the vehicles from service. Aside from improving fuel efficiency, consistent maintenance includes other benefits that can lower the life-cycle costs of owning and operating a vehicle.

Retire Older Vehicles

Another strategy is to simply purchase older vehicles in order to get them off the road. Many older vehicles often are not fuel efficient and produce a considerable amount of pollution. Some estimates attribute 40 percent of all automobile pollution to only 10 percent of automobiles.

Vehicle Speed Control

Vehicle fuel efficiency is in part a function of speed. As the speed of a vehicle increased beyond 55 miles per hour (mph), fuel efficiency typically declines. Since fuel efficiency and the amount of CO_2 a vehicle pumps into the atmosphere are directly related, setting and enforcing a 55 mph speed limit could reduce Utah's CO_2 emissions. Currently, speed limits throughout much of Utah -- particularly in rural areas -- are set well above 55 mph.

Clearly, one disadvantage of lowering and enforcing speed limits is the cost associated with increased travel time. On the other hand, reduced speeds have historically resulted in fewer injuries and fatalities from accidents. The ancillary cost and benefit of a given speed limit need to be considered if Utah chooses to implement this strategy.

Smart Traffic Lights and Highways

City driving is usually characterized by many starts and stops with periods of acceleration and deceleration. Stop lights, traffic jams, poor drivers, and construction are several factors that impede the flow of traffic and decrease vehicle fuel efficiency. To remedy these problems, Utah is implementing the concept of smart traffic lights and highways. Utah adopted an intelligent transportation system (ITS) which includes coordinated traffic signals, real-time cameras to monitor road conditions, and electronic road signs to alert drivers of problems and suggest alternative routes. This information is gathered and dispersed from operation centers.

The ITS has additional benefits beyond improving traffic flow and limiting delays. UDOT cites statistics that ITS reduces accidents and fatalities as well. In addition, vehicles operating with fewer stops and starts tend to require fewer repairs.

Mass Transit - General

One of the main arguments in favor of mass transit is that it benefits from efficiency gains and economies of scale; that is, costs provided by large-scale facilities such as rail or bus tend to be much lower on a per-trip basis as compared with automobile trips. GHG emissions on a per-passenger-mile basis tend to be lower as well. Additional benefits of mass transit may include increasing transportation options for the young, elderly, disabled, poor, or other groups disenfranchised by an automobile-based transportation.

Buses are the primary mode of mass transit in Utah. The Utah Transit Authority (UTA) operates a regional six county system, although, a considerable number of buses are found in school districts and, to a lesser extent, private firms. A new twist in Utah's transportation story is the introduction of the TRAX light rail. The new light rail system opened December 4, 1999, under budget and ahead of schedule, and will cover downtown Salt Lake City and outlying areas along a north-south route. A University route is planned which will ultimately link the downtown area with the University of Utah. Finally, while there are no specific plans to date, heavy commuter or regional rail has been proposed to connect larger cities along the Wasatch Front.

Mass Transit - TRAX

The Utah Transit Authority (UTA) has currently undertaken a project to introduce light rail to Salt Lake County. This project is known as TRAX, which is short for "transit express." The construction of a north-south corridor is completed and the north-south rail began service on December 4, 1999. Powered by overhead electricity lines, TRAX will accelerate from 0 to 55 in 18 seconds and run from 10000 South and 300 East at the southern terminus to downtown Salt Lake City. The length of the corridor is 15 miles with 16 stations, many of which will have park-and-ride lots. The rail line will terminate at the Delta Center in downtown Salt Lake City. The University corridor will extend 2.5 miles from the downtown area to Rice Stadium at the University of Utah.

Each TRAX car will hold approximately 150 people. UTA will operate two cars in tandem, for a total of 300 passengers, and eventually expand to four cars. UTA estimates that by 2010 approximately 23,000 people will ride TRAX daily on the north-south corridor in addition to new bus patrons. The University corridor is estimated to have the same ridership and potential ridership as the north-south corridor.

For purposes of estimating TRAX ridership as a mitigation strategy, an average of 34,000 riders a day is used as a mitigation strategy. Each TRAX car has an expected life span of 30 years and the rail itself has an expected life span of 50 years.

Mass Transit - Doubling of UTA Bus Fleet

UTA is faced with a vexing choice of either providing a limited number of areas with frequent service or many areas with infrequent service. For purposes of equity, the UTA has opted for the latter choice. If UTA were to double the existing bus fleet, however, it could conceivably provide service to more areas more frequently. It is estimated that doubling the fleet size would allow riders to access buses every ten minutes during peak times along the majority of its routes. It is further estimated that a doubling of the fleet would translate to at least a doubling of ridership. The current fleet of 500 buses currently accommodates 85,000 passenger trips daily, so doubling the fleet to 1,000 buses would yield an expected ridership of 170,000.

Mass Transit - Regional Commuter Rail

The Wasatch Front Regional Council (WFRC) and the Mountainland Association of Government

(MAG) and UTA have completed a feasibility study of a heavy rail line to service commuters between Brigham City and Payson, Utah. Though it is still uncertain whether or not the project will be implemented, a commuter rail project has the potential to replace vehicle trips from people with substantial commutes. The project currently under study would have stops in Brigham City, Ogden, Layton, Salt Lake City, Murray, Midvale, South Jordan-Sandy, Lehi, American Fork, Orem, Provo, and Payson. The feasibility study estimates that approximately 4,000 riders would use this service each day on a minimal service level.

Trucking-to-Rail Substitution

The OTA has estimated that the ratio of energy use of trucking compared with rail is 8:1 for intercity transportation. What is unknown is the destinations of freight carried on interstates that would need to be on rail for this savings to be realized. It is assumed that most major cities and many smaller communities have access to both rail and interstates. It is unknown, however, how much any given shipment would differ in trip distance by rail rather than by interstate. As a safe assumption it is assumed that even with differing trip lengths, the average shipment could still realize an energy efficiency gain by switching modes.

Fuel Efficient Airplane Jet Engines

Operating at high speeds and carrying considerable weight, commercial jets consume large quantities of fuel. New technologies may be adopted to increase fuel efficiency. One strategy is to adopt "Ultrahigh Bypass High-Efficiency Engines" which could reduce overall fuel use by roughly 4 percent according to ICF estimates. ICF notes that such a policy is cost effective (assuming engine use of 200,000 miles per year for 15 years under current fuel prices), but that the competitive nature of the airline industry discourages the required up-front investment. Due to the interstate nature of the airline industry, federal action rather than state action would likely be a more feasible approach if regulation is required to induce efficiency improvements.

Table 5-10. Summary of Transportation Sector Strategies

	Quantity (thousand tons)		Cost per ton	
	Feasible	Potential	Feasible	Potential
Tire inflation	48	120	$19	$19
Convert vehicles to natural gas[57]	95	$88	$88	
Enhanced I&M inspection	48	120	$94	$94
Telecommuting	36	60	$108	$108
Rideshare	22	45	$161	$80
Parking Fees	37	75	$173	$173
Buy out old cars	96	240	$223	$223
Convert vehicles to LPG	16	33	$275	$275
Regional (Heavy) Commuter Rail	40	80	NA	NA
Light Rail	34	80	NA	NA
Light Rail Doubled	68	160	NA	NA
Double Buses	45	45	NA	NA
Truck-to-rail substitution	180	240	NA	NA
Heavy-duty Trucks	98	146	NA	NA
Jet Engine Efficiency	29	86	NA	NA
Feebate for mpg	192	480	NA	NA
55-mph speed limit enforcement	634	961	NA	NA
Smart Traffic Lights and Highways	48	96	$7	$7
Total	**1,728**	**3,161**	**$134**	**$122**

C. Transportation Sector Summary

Transportation GHG reduction measures are among the most capital-intensive for any sector. Cost per ton reductions, therefore, are proportionately greater than those in other sectors. Among the least expensive measures are smart traffic systems, tire inflation, inspections, and telecommuting. Cost increases dramatically for strategies such as vehicle conversions and purchases of old cars. Clearly, the most expensive measures are related to those with high capital costs such as light-rail and commuter rail.

VI. Electric Utility Sector

A. Introduction

The following examines the cost and emissions reduction potential of a broad range of measures to reduce emissions from utility generation of electricity for residential, commercial, and industrial use. Measures including fuel switching, CO_2 scrubbing, nuclear generation, or other modifications to large-scale, central stations will not be included. Rather, this section will focus on existing and emerging "clean" electricity generation technologies such as solar, wind, geothermal, and pumped storage (hydro). Distributed generation technologies will also be addressed.

The various measures are evaluated in terms of dollars per ton of GHG reduced. Emissions savings are calculated on a per kilowatt-hour (kWh) basis. Emissions from generating facilities are compared to those from the current portfolio of Utah generating facilities (system average) which are estimated at 0.945 tons per MWh.

The costs of alternative generating technologies have been compared to electricity generation costs on a per kilowatt-hour (kWh) basis. For measures compared with system average-electricity costs, the system average is estimated at 2.5 cents per kWh. This figure is based on the variable (fuel, operating, and maintenance) costs of producing electricity from all generation facilities.

In many cases, transmission and distribution (T&D) credits have been subtracted where measures could be expected to help avoid investments that would otherwise be required. Capacity credits have further been applied when measures could be expected to provide new capacity or to reduce the need for planned new capacity.

It is also assumed that most alternative supply technologies will benefit from minimal incentives extended by the state and federal governments and regulated utilities. These incentives are estimated between 0.05 and 0.50 cents per kWh as applicable. Note that all projects are evaluated in levelized fashion using a real discount rate of 5 percent over a 30 year time frame.

Cost and performance parameters for the following selected strategies are adapted from PacifiCorp's RAMPP-5 (Resource and Market Planning Program), the utility's ongoing integrated resource planning process.

B. Selected Strategies

Solar (photovoltaic)

RAMPP-5 specifies that Utah could theoretically host a 50 MW photovoltaic facility. The dollar per kW for the facility is estimated at $3,000, a figure lower than PacifiCorp's estimate ($4,763) which does not assume a significant price decline for the foreseeable future. A fixed charge rate of 8.4 percent is applied to account for depreciation, insurance, and tax costs. With a capacity factor of 30 percent, total annual kWh is estimated at 197 million kWh.

Project and capacity charges are 16.07 cents per kWh. Fixed O&M costs are estimated at 25.3 cents per kWh and variable O&M costs are estimated at 0.349 cents per kWh. With no fuel costs, and credits for capacity and T&D, the adjusted cost of energy (ACOE) is estimated at 40.92 cents per kWh, yielding a cost per ton of $406.52. Table 5-19 below provides more information on the levels of reduction relating to three levels of kWh output.

Table 5-11. Solar PV Cost and CO_2 Reduction

	Low	Feasible or Best Estimate	Potential or High
Tons CO_2	186,259.50	372,519.00	558,778.50
Annualized $/ton CO_2	$406.52	$406.52	$406.52

Geothermal

In addition to the 23 MW Blundell geothermal plant currently operated by PacifiCorp, the RAMPP-5 modeling process indicates that Utah could host added geothermal capacity. The proposed project is rated at 50 MW with a capital cost of $2,376 per kW. The fixed charge rate is somewhat higher at 10.5 percent as is the capacity factor (80 percent). Total annual generation is estimated at 350 million kWh.

Project and capacity charges are 7.25 cents per kWh. Fixed O&M costs and variable costs are estimated at 3.2 cents and 0.2 cents respectively. Including government and utility incentives, the ACOE is 8.69 cents per kWh. The cost per ton of CO_2 reduced is calculated as $84.69. Three levels of reduction potential are included based on installed capacity.

Table 5-12. Geothermal Cost and CO_2 Reduction

	Low	Feasible or Best Estimate	Potential or High
Tons CO_2	372,519.00	745,038.00	1,117,557.00
Annualized $/ton CO_2	$84.69	$84.69	$84.69

Hydro (pumped storage)

PacifiCorp has modeled pumped storage operations for its hydroelectric facilities. A proposed 200 MW facility carries a capital cost of $816 per kW. The fixed charge is estimated at 15 percent and the capacity factor at 30 percent. Annual generation is figured at 526 million kWh.

Table 5-13. Hydro (pumped storage) Cost and CO_2 Reduction

	Low	Feasible or Best Estimate	Potential or High
Tons CO_2	496,692.00	496,692.00	496,692.00
Annualized $/ton CO_2	$65.53	$65.53	$65.53

Project and capacity charges are 6.29 cents per kWh. Fixed O&M costs are calculated as 3.2 cents per kWh with no accounting for variable O&M costs.

The ACOE is calculated as 8.69 cents per kWh, yielding a cost per ton reduction value of $65.53. As Table 3 indicates, since only one pumped storage project is proposed, there is no variation in reduction potential.

Wind Power

Among the more economically viable generation technologies is wind power. PacifiCorp proposes a modest level of wind capacity (50 MW) in its RAMPP-5 model. Capital costs are estimated at $1,215 and the fixed charge rate is given as 8.4 percent. A 30 percent capacity factor gives rise to an annual generation level of 131 million kWh. Project and capacity charges are 6.51 cents per kWh. Fixed O&M costs are minimal at 6.4 cents per kWh with no assumed variable O&M costs.

The ACOE for with the basic wind project is 12.12 cents per kWh. The cost per ton of emissions reduced is estimated at $101.66. As many as three projects are considered in the "potential or high" case. Table 5-22 presents these estimates.

Table 5-14. Wind Power Cost and CO_2 Reduction

	Low	Feasible or Best Estimate	Potential or High
Tons CO_2	124,173.00	248,346.00	372,519.00
Annualized $/ton CO_2	$101.66	$101.66	$101.66

Distributed Resources

Distributed resources refer to the combined or individual use of electricity generation, storage, distribution, load management, and efficiency measures in specific locations to delay or eliminate transmission and distribution (T&D) system capital investments.

Table 5-15. Range of Distributed Power Technologies

TECHNOLOGY	SIZE-RANGE
Microturbines	30 - 200 kW
Miniturbines	200 - 1,000 kW
Small Turbines	1,000 - 15,000 kW
Reciprocating Engines	30 - 15,000+ kW
Fuel Cells	30 - 1,000 kW
Fuel Cell Hybrids	200 - 1,000 kW

Source: Power*Value*. May/June 1999.

Distributed power technologies include renewable (such as solar photovoltaics, and wind) as well as reciprocating engines, microturbines, and fuel cells. Table 5-23 presents a range of common distributed power technologies.

Current trends in the U.S. energy industry clearly favor the adoption of distributed generation, particularly from the standpoint of increased energy efficiency and reduced GHG emissions. The characteristics of these technologies and locations (close to the load served) make them ideal resources to help energy suppliers address regulatory, environmental, and competitive challenges in delivering essential power services to a range of power customers.

While the above technologies may ultimately prove of great value in diversifying the nation and Utah's portfolio of generation resources, it is the large-scale, utility-sponsored projects which will likely prove to be more economically attractive in the near term. This section, therefore, focuses specifically on distributed generation relating to the avoidance of T&D investments by an independent distribution company (DISCo) or the distribution end of an integrated distribution, transmission, and generation utility.

A prime candidate for utility-sponsored distributed generation is a simple cycle combustion turbine. RAMPP-5 provides cost and performance parameters for a 135 MW system. Such a facility carries a capital cost on the order of $461 per kW, with a fixed capital charge of 15 percent, and a capacity factor of 80 percent. Annual generation is estimated at 946 million kWh.

Table 5-16.

	Low	Feasible or Best Estimate	Potential or High
Tons CO_2	421,005.60	842,011.20	1,263,016.80
Annualized $/ton CO_2	$147.35	$147.35	$147.35
Tons CO_2	617,474.88	1,234,949.76	1,852,424.64
Annualized $/ton CO_2	$32.52	$32.52	$32.52

Project and capacity charges are 1.33 cents per kWh. Fixed O&M and variable costs are estimated at 5.3 cents and .01 cents respectively. Fuel costs are estimated at 2.4 cents per kWh, rising at a real escalation of 2.5 percent annually.

• *Simple-Cycle Combustion Turbines*

Project and capacity charges are 1.33 cents per kWh. The ACOE for the simple-cycle combustion turbine is 9.06 cents with an annualized dollar per ton reduction cost of $147.35. Table 5-16 below shows the varying levels of reduction based on installed capacity and generation.

• *Combination Combustion Turbines*

The combination of combustion turbines, configured as topping and bottoming cycles, is known as a combined cycle facility. Operated as such, these facilities exploit the thermodynamic advantages of cogeneration systems which recycle waste heat for use in an additional turbine. As a result, a given amount of fuel is worked twice to improve the unit's overall efficiency. RAMPP-5 identifies this technology as appropriate and viable for Utah. Specifically, PacifiCorp is considering a 198 MW facility with a capital cost of $561 per kW. With a fixed capacity charge and a capacity factor of 80 percent, such system is capable of producing 1,390 million kWh per year.

Project and capacity charges are 1.62 cents per kWh. Fixed O&M and variable costs are 1.2 cents and 0.05 cents respectively. Fuel costs are estimated at 1.4 cents per kWh and are expected to rise at a real annual rate of 2.5 percent. The ACOE is estimated at 3.95 cents per kWh and the cost per ton of CO_2 removed is $32.52. Table 5-16 above shows the potential reduction for differing levels of generation.

VI. Land-Use Planning

A. Introduction

America's cities and towns account for over 80 percent of national energy use. Land-use planning and urban design affect about 70 percent of that amount, or 56 percent of the nation's total energy use. For example, the density, mix, and spatial arrangement of land uses in a community heavily influence the amount and mode of travel and, therefore, transportation energy use. These same urban characteristics also affect the amount of energy needed to heat and cool private buildings and operate public or community infrastructure.

The Spatial Patterns of Energy Use and Emissions

According to Owens (1986), several dimensions of urban planning influence energy demand and, ultimately air quality. These dimensions and related effects on energy demand are found in Table 5-17 below.

Table 5-17. Influence of Urban Planning on Energy Demand

Planning Variables	Energy and Air Quality Link	Effect on Energy Demand
Shape of urban boundaries	Travel requirements	Energy use variation up to 20%
Shapes and sizes of land-use designations	Travel requirements (trip length and frequency)	Variation up to 150%
Mix of activities	Travel requirements (trip length)	Variation up to 130%
Density/clustering of trips	Transit feasibility	Energy savings of up to 20%
Density and mix	Space conditioning needs and district energy	Savings of up to 15%. Efficiency of primary energy use improved up to 30% with district heating and cooling.
Site layout/orientation	Solar use feasibility	Energy savings of up to 20%.
Siting/landscaping	Microclimate improvements	Energy savings of at least 5%; more in exposed areas

Source: Owens, Susan E., Energy, Planning and Urban Form, Pion Publishing, London, 1986

Table 5-18. Typical Community Energy Uses

	Energy Use (MMBtu/yr)	Energy Cost ($/yr)	(CO_2 tons/yr)
Single-family home (2.5 persons)	110	$1,280	13
10,000 sq. ft. store	850	$10,240	129
20,000 sq. ft. office	2080	$25,180	317
Auto (avg. 1.1 occupants)	80	$740	6
Bus (avg. 10 occupants)	1300	$10,380	103
Total Per Capita	50	$1,650	17

Sources: EIA, Annual Energy Outlook 1994. EIA, Commercial Buildings Survey 1993. USDOE, Transportation Energy Data Book 1994.

Table 5-19. Energy Effects of Residential Density (Total operating energy use per household)

Units/Acre	Energy (MMBtu/yr)	Cost ($/yr)	CO_2 (tons/yr)
3	440	$4,800	50
6	410	$4,600	49
12	380	$4,300	47
24	360	$4,100	47
48	340	$3,900	45
96	310	$3,700	42

Sources: EIA, Annual Energy Outlook 1994. EIA, Commercial Buildings Survey 1993. USDOE Transportation Energy Data Book 1994.

Creating energy efficient communities requires measuring energy demand and supply for housing, employment, transportation, and infrastructure. These measurements are similar to other calculations that tabulate dwellings, residents, workers, traffic, and other variables used in city planning. Table 5-18 provides an overview of common energy uses.

Density is a key variable in the urban energy and emissions relationship as demonstrated by Table 5-19, which shows the relative difference between residential densities. A description of each density scenario follows below:

- **3 units/acre** – Assumes single-family subdivisions on 10,000 sq. ft. lot which are auto dependent.
- **6 units/acre** – Includes detached housing on 5,000 sq. ft. lots with commuter-oriented transit service available.
- **12 units/acre** – Townhouses are situated on 2,500 sq. ft. lots, with attached walls to reduce

energy use, and a high level of transit service to employment centers.

- **24 units/acre –** Assumes low-rise apartments with walking and transit trips equal to auto use. Shared walls contribute to lower energy use per apartment.
- **48 units/acre –** This scenario consists of mid-rise apartments wherein transit and pedestrian trip exceed auto use and energy use per apartment is reduced further.
- **96 units/acre –** This residential density consists of high rise, very high transit and pedestrian activity. Very low building energy use per apartment is assumed.

Table 5-20. Urban Energy Use Per Household

Activity	Energy (MMBtu/yr)	Cost ($/yr)	CO_2 (tons/yr)
Travel	80	$910	6
Home	100	$1,220	12
Community Fraction	140	$1,650	21
Total	320	$3,780	39

Sources: EIA, Annual Energy Outlook 1994. EIA, Commercial Buildings Survey 1993. USDOE Transportation Energy Data Book 1994.

Energy demand and emissions are also greatly influenced by residential spatial patterns. Tables 5-20 and 5-21 below show the relative differences in energy consumption and CO_2 emissions between urban and suburban households. The categories of energy demand and emissions include travel, home, and "community fraction." Community fraction includes the household share of all non-residential energy use and community infrastructure energy use. For purposes of comparison, each household is assumed to have 2.5 persons.

Table 5-21. Suburban Energy Use Per Household

Activity	Energy (MMBtu/yr)	Cost ($/yr)	CO_2 (tons/yr)
Travel	140	$1,670	11
Home	110	$1,340	14
Community Fraction	190	$2,280	29
Total	440	$5,290	54

Sources: EIA, Annual Energy Outlook 1994. EIA, Commercial Buildings Survey 1993. USDOE Transportation Energy Data Book 1994.

Among the prime land-use planning strategies for mitigating GHG emissions is mixed use. Table 5-22 below shows the energy and emissions associated with various mixes of offices and residences. Energy use is limited to building and travel only and the community fraction is not included. Jobs are limited to offices only.

Land-Use Planning in Utah

The current period of land-use and growth planning in Utah began in earnest with the 1995 Growth Summit, a conference sponsored by legislative leadership and the Governor intended to promote legislative solutions to the growth challenges facing the state. Over 60 proposals suggesting ways to manage the state's growth were submitted. The Summit resulted in a 10-year transportation improvement plan for the state.

Table 5-22. Energy Effects of Land-use Mix

Land-Use Mix/Acre	Energy (MMBtu/yr)	Cost ($/yr)	CO_2 (tons/yr)
Retail	61100	$566,400	5020
Office	17000	$168,300	1660
Jobs/Housing (4:1)	8200	$83,800	860
Jobs/Housing (1:4)	4600	$48,500	530
Jobs/Housing (1:1)	5500	$57,700	620

Sources: EIA, Annual Energy Outlook 1994. EIA, Commercial Buildings Survey 1993. USDOE Transportation Energy Data Book 1994.

The following year the Governor created the Utah Critical Lands Conservation Committee. The Committee supported numerous open space projects and developed educational materials describing the tools and techniques for open space conservation.

In 1997, the state partnered with Envision Utah, a public/private community partnership to study the effects of long-term growth along the Greater Wasatch Area of northern Utah, creating a publicly supported vision for the future, and advocating the necessary strategies to achieve this vision. Governor Leavitt is the Honorary Co-Chair of Envision Utah. Concurrently, the Quality Growth Efficiency Tools (QGET) Technical Committee was formed. Sponsored by the Coalition for Utah's Future, Envision Utah and its partners - with extensive input from the public - aim to create a publicly supported growth strategy that will preserve Utah's high quality of life, natural environment and economic vitality during the next 50 years.

The Role of Envision Utah

The Envision Utah partnership includes state and local government officials, business leaders, developers, conservationists, landowners, academicians, church groups and private citizens. This unique and diverse coalition is collaborating to produce a common vision for the Greater Wasatch Area - the region bordered by Brigham City in the north and Nephi in the south, and stretching from Heber City in the east to Tooele in the west - as it confronts the prospect of growth in the coming decades.

The Public's Role in Envision Utah

Vital to the success of Envision Utah's efforts is public input. Meetings, surveys and open workshops have been held throughout the region and will continue to occur as Envision Utah's efforts proceed throughout 1999. Particularly crucial is citizen input on the four alternative growth choices. The ideas and opinions contributed during this phase will be key to the creation of a preferred growth choice, which will be used as a guide for determining how the Greater Wasatch Area will grow in the years ahead.

The Envision Utah Process

The first phase of the Envision Utah process is the development of a broadly supported strategy to guide the future of the Greater Wasatch Area. From its inception, Envision Utah began the challenge of bringing together major public and private entities for a cooperative effort to deal with Utah's growth. Specifically, the work of Envision Utah includes:

- An in-depth study and a broad survey of area residents, conducted by the research firm Wirthlin Worldwide, to determine Utahns' values and to find out what they most want to preserve or change in the face of Utah's rapid growth. *(May 1997)*
- A baseline model generated with extensive state-of-the-art computer tools (Quality Growth Efficiency Tools - QGET) by the Governor's Office of Planning and Budget. This model projects the effect of Utah's growth during the next 20 to 50 years if current trends continue. *(September 1997)*
- A series of public workshops held throughout the Greater Wasatch Area, which collected opinions and data from citizens on how to shape future development. These workshops - which included extensive work on regional maps and explored important topics such as land-use, transportation and open space preservation - provided valuable public input, which has been vital to the development of four alternative growth scenarios. *(Spring and Summer 1998)*
- The development of four alternative growth scenarios, which show possible development patterns that could result if various growth strategies are implemented during the next 20 to 50 years. An extensive analysis of these alternative scenarios was conducted to determine and demonstrate the relative costs and impacts of each strategy on population, infrastructure cost, air quality, water, open space and recreation preservation, traffic congestion, affordable housing, business patterns and other significant topics. *(Fall 1998)*
- A widespread public awareness, education and mass media campaign to encourage area residents to express their preferences on how they want their communities and the region to develop, and to increase understanding of the options and challenges inherent to growth. In addition to a thorough public survey, a series of workshops will be held to garner public input regarding specific growth scenarios. *(Winter and Spring 1999)*.
- The development of a preferred growth scenario which will serve as a broadly and publicly supported growth strategy for the Greater Wasatch Area in the years to come. *(Summer and Fall 1999)*

Implementation

Through a multi-year implementation plan, Envision Utah will promote the publicly supported strategy in order to improve growth management and land-use policies and practices, at all appropriate levels throughout the region. In addition, all public and private entities will be encouraged to voluntarily make planning decisions consistent with the vision of the preferred growth scenario vision.

In-Depth Scenario Analysis

Scenario A

Scenario A demonstrates how the region could develop if the pattern of dispersed development occurring in some communities today were to continue unabated. New development would likely take the form of single-family homes on larger, suburban lots. Most development would focus on automobile convenience, and transportation investments would support auto use.

Average lot sizes and concise distances between homes would increase. Most housing would be single-family homes on larger lots (¼ acre and larger), providing many with opportunities for large yards and suburban living. This could, however, create a shortage of rental housing in the region, which the market would accommodate by encouraging conversion to more single family homes into rental properties. The larger lot sizes would cause more new land to be developed in Scenario A than in any of the other scenarios, leaving less land for open space and agriculture. The supply of undeveloped land would diminish more quickly, possibly causing an increase in land and housing costs. Infrastructure costs (transportation, water, sewer, and utilities) would also increase because of additional roads and longer transmission lines. These infrastructure costs would vastly exceed those of any other scenarios.

Because development would cover a larger area and travel would be more auto-oriented, Scenario A would require significant freeway system expansion and more miles of new arterial streets. Mass transit would not serve the dispersed population very effectively. Most of the transportation investment would be geared toward improving automobile use. The increased investment would result in faster speeds, but the dispersed development pattern would cause longer trips, with the end result being about the same amount of time spent on the road.

Characteristics

Housing:

- People live farther apart and have more privacy
- Most new homes are single family homes on large lots
- Fewer housing choices than today; less housing available in all categories except large-lot, single-family
- Single-family homes would represent 77 percent of the housing mix, up from 68 percent in 1990
- Average size of single family lot increases from 0.32 acre today to 0.37 acre in 2020

Transportation:

- People benefit from convenience of automobile travel
- Fewer transportation choices, due to increased reliance on automobile travel
- Families will require more cars
- More money required for highway development
- Only 1.5 percent of population has easy access to rail transit

Land:

- Land is consumed faster than other scenarios
- Urbanized area grows by 95 percent from 1998-2020
- Open space and farmland are consumed more rapidly than in any other scenario
- Re-use of existing urban areas is minimal

Cost:

- Affordable housing farther away from jobs and services as compared with other scenarios
- Infrastructure most expensive of all scenarios
- Personal transportation costs highest of all scenarios

Water:

- Water demand highest of all scenarios, primarily because of outdoor water use

Air Quality:

- More vehicle travel creates worst air quality of all scenarios

Scenario B

Scenario B shows how the region would develop if state and local governments followed their 1997 plans. Development would continue in a dispersed pattern, much like it has for the past 20 years, but would not be as widely dispersed as in Scenario A. New development would primarily take the form of single-family homes on larger, suburban lots (¼ acre and larger). Most development would focus on convenience for auto users and transportation investments would support auto use.

Lot sizes and distance between homes would remain near their current averages. Most new housing provided would be single-family homes on large lots, providing many residents with opportunities for large yards and suburban living. There could be a few more rental opportunities than in Scenario A, but could still fall short of meeting current market demands. Many single family homes would likely be converted into rental properties to meet the extra demand. This scenario would consume a large amount of raw land, although not as much as Scenario A, limiting the land available for open space and agriculture.

The available supply of land would be consumed quickly, possibly leading to increased land and housing costs. Infrastructure costs (transportation, water, sewer, and utilities) would also increase over the next 20 years, and would be the second highest of all scenarios. Transportation expenditures would be focused on upgrading the existing freeway system and extending surface streets into newly developed areas. Street and highway expenditures would be lower than in Scenario A, but speeds would be lower as well. Although this scenario does not add any rail transit beyond the Downtown-Sandy line currently in operation, it does envision some expansion and reconfiguration of bus service.

Characteristics

Housing:

- Average lot size remains at current level
- Most new homes are single family homes on large lots
- Fewer housing choices than C & D; less housing available in all categories except large-lot, single-family
- Single family homes would represent 75 percent of the overall housing mix, up from 68 percent in 1990
- A few more condos, apartments, small lot homes than A

Transportation:

- People benefit from convenience of automobile travel
- Fewer transportation choices, due to increased reliance on automobile travel. Compared to the other scenarios, this means:
- Increasing vehicle travel
- Families need to own more cars
- Increasing congestion
- Only 1.7 percent of population has easy access to rail transit

Land:

- Land is consumed almost as quickly as in A
- Urbanized area grows by 75 percent from 1998-2020
- Reuse of existing urban areas is minimal

Cost:

- Few affordable housing options near jobs and services
- Infrastructure second most expensive of all scenarios
- High personal transportation costs

Water:

- Water consumption second highest of all scenario

Air Quality:

- Second best air quality of all scenarios

Scenario C

Scenario C shows how the region might develop if we were to focus more of the new development in walkable communities that contained nearby opportunities to work, shop, and play. Communities would accommodate a portion of new growth within existing urbanized areas, leaving more undeveloped land for open space and agriculture. New developments would be clustered around a town center, with a mixture of retail services and housing types close to a transit line. These communities would be designed to encourage walking and biking, and would contain a wide variety of housing types, allowing people to move to more or less expensive housing without leaving the community.

Average lot sizes would be smaller than today. Most of the new housing provided would still be single-family homes on large lots, but more apartments, townhouses, condominiums, and small-lot single-family homes would be provided than in A or B. This would likely meet the market demand for rental housing. Smaller lot sizes would allow Scenario C to consume raw land less quickly, leaving more land available for open space and agriculture, and providing suburban and rural living opportunities further into the future. Infrastructure costs (transportation, water, sewer, and utilities) would be lower in Scenario C than in any other scenario.

Because Scenario C focuses new development into more compact land-use patterns, walking and biking would become more feasible. This would also make mass transit a highly effective means of serving the population, providing a greatly increased number of people with convenient alternatives to the automobile. Scenario C would therefore propose large-scale expansion of the rail system, and reconfiguration of bus service to complement rail service. Transportation investments would be focused much more heavily on transit than they are today, with most road investments going into improvement of existing roads rather than construction of new ones.

Characteristics

Housing:

- Average size of single family lot decreases from 0.32 acre today to 0.29 acre in 2020
- Homes are closer together; most new homes are single family homes on large lots
- Wider variety of housing options available than in Scenarios A or B, including townhouses, condos, apartments, and small lot homes
- Much of new housing would be located in villages and towns situated along major roads and rail lines

Transportation:

- More transportation options
- Lower per-person transportation costs
- Families can operate with fewer cars
- Some 25 percent of population has easy access to rail transit
- Rail transit provides convenient access to most Salt Lake area communities

Land:

- Land consumption is slower than Scenarios A and B
- Urbanized area grows by 29 percent from 1998-2020
- New development is placed within existing urban areas and clustered around transit routes, leaving more land for open space and farmland

Cost:

- Diversity of housing options makes affordable housing available closer to jobs and services
- Lowest infrastructure costs of all scenarios
- Lower personal transportation costs than A or B

Water:

- Second lowest water consumption of all scenarios

Air Quality:

- Best air quality of all scenarios

Scenario D

Scenario D shows how the region might develop if Scenario C were taken one step further, focusing nearly half of all new growth in existing urban areas. This would leave more undeveloped land for open space and agriculture than any of the other scenarios. When new land is used, development would be clustered around a town center, with a mixture of commercial and housing types close to some portion of a greatly expanded transit system. These communities would be designed to permit and encourage walking and biking, and would contain the widest variety of housing types of any scenario.

Average lot sizes would be smaller than in all other scenarios. Most new housing would be townhouses and single-family homes on small lots, and more apartments, townhouses, condominiums, and small-lot single-family homes would be available than in the other scenarios. Scenario D would consume the smallest amount of new land, leaving more land available for open space and agriculture than the other scenarios. Infrastructure costs in Scenario D would be lower than A and B, but somewhat higher than C, as clustering of so many new residents into existing urban areas would necessitate improvements to existing infrastructure.

Because Scenario D focuses new development into more compact land-use patterns, mass transit would serve a larger share of the population, providing many more people with convenient alternatives to the automobile. Scenario D would propose large-scale expansion of the rail system, with additional spurs for access to downtown Ogden and Provo. Transportation investments would be focused very heavily on transit, with most road investments going into improvements of existing roads, rather than construction of new ones.

Characteristics

Housing:

- Average size of single family lot decreases from 0.32 acre today to 0.27 acre in 2020
- Homes are closer together than in all other scenarios most new homes are single-family homes or townhouses, but on smaller lots than in A or B
- Wider variety of options available than in other scenarios
- Most new housing would be located in existing urban areas and in villages and towns situated along major roads and rail lines

Transportation:

- Greatly expanded transit system augments road network to provide more transportation options
- Some 32 percent of population has easy access to rail transit
- Convenient transit access to most Salt Lake area communities, Ogden, and BYU

Land:

- Land consumption is slower than all other scenarios
- Urbanized area grows by 20 percent from 1998-2020
- Large portion of new development is placed within existing urban areas most other development is clustered around transit routes, leaving more land for open space and farmland than any other scenario

Cost:

- Diversity of housing options makes affordable housing closer to jobs and services than in other scenarios
- Second lowest infrastructure costs of all scenarios
- Lowest personal transportation costs of all scenarios

Water:

- Lowest water consumption of all scenarios

Air Quality:

- Better air quality than in A, worse than B or C

Land-Use Planning and Emissions Reduction

Tables 5-17 through 5-22 (beginning on page 5-32) provide the basic spatial relationships required to determine how different land-use patterns may provide energy and emissions savings. To a degree, these relationships may be correlated with Scenarios A through D to determine, in a relative sense, how each scenario compares in terms of energy consumption and CO_2 emissions.

According to QGET statistics, Utah will host 775,190 households by the year 2010. According to the description given for Scenario A, some 77 percent of these households are assumed to be single and detached, similar to the "3 unit/acre" case in Table 5-19. Assuming that the remaining 23 percent are based on the "6 unit/acre" model, the total tons of CO_2 is estimated at 38,581,206.

In Scenario B 75 percent of the households are again characterized according to the 3 unit/acre model. Based on the description provided by Envision Utah, Scenario B incorporates alternative housing options including the 6 unit/acre and 12 unit/acre (townhouse) cases. Assuming weights of 15 percent and 10 percent respectively, the total tons of emissions is calculated at 38,410,665.

Scenario C assumes that 75 percent of the single and detached housing is based on the 6 unit/acre model with the remaining 15 percent and 10 percent consisting of 24 unit/acre (low-rise apartments) and 48 unit/acre (mid-rise apartments) cases. Total emissions for this scenario decline to 37,441,678 tons of CO_2.

Finally, Scenario D assumes that 75 percent of single detached housing is comprised of the 6 unit/acre model with 15 percent based on the 48 unit/acre mid-rise apartments townhouse and 96 unit/acre (high-rise apartments) models. Scenario D yields 36,976,564 tons of CO_2 per year.

Overall, there is relatively little difference between Scenarios A and B. The savings from Scenario C over A amount to roughly 1.1 million tons per year. Scenario D saves over 1.6 million tons per year as compared with Scenario A.

As evident from this analysis, increases in residential density do not provide dramatic gains in emissions reduction since the proportion of high-density housing in all scenarios, except for Scenario D, is relatively small. To fully exploit the benefits of high-density housing, planners should consider, for example, cogeneration and district energy options to reap the maximum energy efficiency gains.

Part Six
Non-Fossil Greenhouse Gas Emissions

I. Industrial Sources

GHG emissions result not exclusively from the combustion of fossil fuels but also from chemical and industrial processes. In the U.S. economy, most of these emissions stem from the calcination of limestone (calcium carbonate, $CaCO_3$ to form lime (CaO). Though emissions from calcination are generally attributed to the cement industry, limestone and lime are used in a wide variety of industrial applications. Additional carbon is contributed by the production and consumption of soda ash (Na_2CO_3). Carbon emissions from these sources in the United States have increased in recent years due to high levels of construction and industrial activity, a trend notable in Utah as well.

A. Limestone Use

Process Overview

Limestone refers to the classification of carbonate rocks used as the basic building blocks in the construction industry. The primary applications of limestone include aggregate, lime, cement, and building stone. Limestone can also be used as a flux or purifier in metallurgical furnaces, as a sorbent in flue gas desulfurization (FGD) systems in utility and industrial plants, or as a raw material in glass manufacturing. Limestone is heated during each of these processes, generating CO_2 in the process.

Emissions Reduction Potential

While the production of lime accounts for the majority of carbon emissions associated with the consumption of limestone, carbon emissions also result from its direct consumption. FGD commands the largest fraction of the direct use market where limestone is used primarily in coal-fired electric generating plants to remove sulfur oxides from stack gases either during or after the combustion of fossil fuels.

The wet lime/limestone scrubber is the most common FGD system, comprising about 70 percent of all installed FGD capacity in the US. In these systems, flue gas passes through the FGD absorber, where sulfur dioxide is removed by direct contact with an aqueous suspension of finely ground limestone, before its release into to the atmosphere from a stack or a cooling tower. The byproducts of this reaction are either a mixture of calcium sulfate/sulfite or gypsum, which can be sold for use in plaster, cement, and wallboard.

The demand for FGD systems derive from the 1990 Clean Air Act Amendment. Though highly efficient at sulfur dioxide removal, FGD is associated with increased CO_2 emissions for two reasons. First, as a sorbent, limestone reacts with sulfur dioxide to produce calcium sulfate, CO_2, and oxygen. Second, since the FGD requires energy for its function, power plant efficiency is derated by 1 to 2 percent thus increasing fuel consumption to meet electricity loads.

Because limestone is used directly in chemical reactions, there are relatively few opportunities for improving the efficiencies of converting it into various products. Co-firing of natural gas with coal in power plant or industrial applications is perhaps the only strategy that could significantly reduce the direct use of limestone and, hence, the production of CO_2 in fossil-fired generation facilities.

The Utah Limestone Industry

Nine companies quarried 2.2 million short tons of limestone and dolomite (a related carbonate material) in 1998. The three largest suppliers of crushed aggregate used in construction are Valley Asphalt from two quarries in Utah County, Larsen Limestone from one quarry in Utah County and Harper construction from one quarry in Salt Lake County.

Geneva Steel quarries their own dolomite and limestone, from a Cambrian carbonate section, for use as flux at their Orem steel mill. Barring a significant change in its steelmaking process, which is unlikely given the firm's financial condition, this use will likely remain unchanged or even decline.

In utility applications, Cotter Corporation mines roughly 25,000 tons per year (tpy) of limestone from the Pennsylvanian Hermosa Group in San Juan County for FGD at the Nucla, Colorado power plant. In Utah, Rancho Equipment Service (RES) mines limestone from the Ordovician Pogonip Group in central Juab County for FGD at the Intermountain Power Project's (IPP) generating station near Delta in Millard County. RES produces approximately 200,000 tpy for the IPP application. Finally, the Coval Company produces limestone from the Mississippian Desert Limestone from the old Larsen Limestone Company property in Utah County for FGD at the Bonanza power plant located near Vernal. Overall, the demand for limestone in utility applications will track the demand for electric power both within Utah and for the export market.

In other applications, Emery Industrial Resources mines 30,000 tpy of limestone from the Tertiary Flagstaff Limestone in eastern Utah County for coal-mine rock dusting. Western Clay Company also produces limestone from the same area for rock dusting and for crushed stone.

Demand for limestone in these applications should continue to track production at Utah's coal mines, which in turn are related to electricity production. Utah's Division of Air Quality estimates that year 2010 emissions from this sector should reach 1,007,199 tons. Assuming a 10 percent reduction due to process efficiency improvements, savings could reach 100,720 tons. Cost effectiveness, however, cannot be estimated due to a lack of capital cost and O&M estimates for the various processes.

B. Lime Production

Process Overview

A versatile chemical used in a wide range of industrial, chemical, and environmental applications, lime is a calcined or burned form of limestone commonly referred to as quicklime. Because the basic production of lime is such as relatively straightforward a process, it has not been the subject of considerable investigation. Instead, much of the process research has focused on the operation of kilns. Only in the last 25 to 30 years, prompted largely by higher energy prices, has attention focused on the thermodynamics and kinetics of calcination and hydration reactions.

Lime production involves three main stages: stone preparation, calcination or burning, and hydration. CO_2 is generated during the calcination stage, when limestone is roasted at high temperatures. In contrast with the Portland cement industry, which utilizes rotary kilns with preheaters almost exclusively, lime calcining may employ a wide range of procedures for customized purposes.

Emissions Reduction Potential

Vertical kilns for calcining are typically used for larger stones and may use oil, natural gas, or coke. In some instances pulverized coal may be used. Multiple shaft kilns are designed for smaller stones and, because of a novel heat regenerative system, these kilns are among the most efficient.

The most efficient systems overall, however, employ external preheaters in medium length kilns. With these systems, exhaust gases from the kiln are drawn counter-current through the stone preheating it to 540 to 900 degrees Celsius. During preheating, approximately 30 percent calcination is achieved before the stone is discharged into the kiln. Heat exchangers and coolers which recuperate waste heat are also utilized to affect improved fuel efficiency.

Over the past 30 years the steel industry has been the major consuming market for lime. Imports of steel and automobiles have curtailed these uses and the likely increased use of polymer composites will also limit growth in the use of lime in steel production. Nevertheless, the basic oxygen furnace (BOF) still dominates and continues to use approximately 80 percent of all lime produced. A typical BOF requires 65 kg/t versus 30 kg/t for electric furnaces or mini-mills. In both of these applications, lime is used as a scavenger or flux to remove impurities such as phosphorous, silica, alumina, and sulfur.

Lime is used in non-ferrous metallurgy as a method to neutralize sulfur acid wastes, as a scavenger for impurities, and as a pH neutralizer. Applications include copper, alumina, and magnesia production. Lime is also used in the paper and pulp industry for bleaching and in the chemical manufacturing of alkalies, inorganic chemicals, and organic chemicals. Among the newest applications for lime include soil stabilization and lime-fly ash for use in roadbed construction.

Among the markets with greatest potential include water and waste treatment and FGD applications. In the case of water and waste treatment, lime is used in combination with soda ash to soften water in systems where ion exchange processes are not employed. Lime is also used as a secondary agent to chlorine for killing bacteria. Finally, lime can be used for absorbing iron, magnesium, and organic tannins from untreated water.

In the case of FGD, advanced scrubber technologies such as the Dravo Corporation's patented Thiosorbic process rely exclusively on lime as an absorbent for oxides of sulfur. Overall, the water and waste treatment and FGD markets should remain strong in the face of ever stringent EPA requirements affecting water quality.

From the standpoint of energy efficiency improvements, it is important to bear in mind that in each of the above applications, higher thermodynamic efficiencies have been attained through the conversion from long rotating kilns to short preheater kilns.

Table 6-1. Lime Production Unit Operations

Unit Operation	Electricity	Fuel	Hot Air
Crushing & Grinding	15.0		
Screening & Classify	8.0		
Kiln	11.0	2800.00	381.5
Cooling	17.0		
Screening & Classify	8.0		
Crushing & Grinding	16.1		
Hydrator	14.7		
Milling Separator	1.0		
Packaging	1.0		
Electricity Generation	0.3		

Source: "Energy Analysis of 108 Industrial Processes". Harry L.

Table 6-1 identifies the individual steps or "unit operations" associated with the production of lime. Indicated also are the energy inputs expressed as Btu per unit flow.

As apparent from the table, kiln operations account for the largest share of energy input. However, because most processes are optimized at this stage, the remaining areas for reduction are in the crushing and grinding stages, which largely consist of electric motor operations. Information on the costs of motor improvements for these process stages, however, was not recovered. Therefore, no cost effectiveness measure is offered.

It is assumed that the demand for lime will track the rate of building construction growth. Emissions are estimated to grow at a rate of 1.9 percent yielding a 2010 GHG emissions estimate of 444,732 tons. As compared with limestone, more opportunities exist for efficiency improvements because the process is more complex and involves more stages. It is estimated, therefore, that process efficiency could be increased by 15 percent, translating into a year 2010 savings of 66,710 tons.

The Utah Lime Industry

Lime demand and production have remained strong in Utah in recent years. Continental Lime, Inc., located east of Sevier Lake, produces about 730,000 tpy of high-calcium quicklime in three rotary kilns with feed provided by the Cambrian Dome Formation. Of note, the plant is rated as one of the 10 largest lime plants in the United States. Chemical Lime of Arizona operates a plant near Grantsville in Tooele County and produces roughly 90,000 tpy of dolomitic quicklime and hydrated lime from the Ordovician Fish Haven Dolomite. In 1995, the firm purchased the old Marblehead plant in Tooele County from U.S. Pollution Control.

C. Cement Production

Process Overview

Cement production is among the largest sources of non-fossil emissions in the Utah. Specifically, CO_2 results from the heating of limestone, which constitutes approximately 80 percent of the feed to cement kilns. During cement production, high temperatures are employed to transform the limestone into lime, releasing CO_2 to the atmosphere.

Portland cement, the most commonly used hydraulic cement, requires at least four chemical elements: calcium, silicon, aluminum, and iron. Derived from naturally occurring rocks and minerals (such as limestone, clay, shale, and iron), the materials are ground into a very fine powder and fed into a rotary kiln and heated to temperatures up to 1,500 degrees Celsius. It is in the direct firing in the cement kilns that results in calcination and the release of CO_2.

In this last process, one molecule of calcium carbonate is decomposed into one molecule of CO_2 and one molecule of calcium oxide. Because the process consumes nearly 100 percent of the calcium oxide, the amount of remaining calcium oxide is a good measurement of the amount of CO_2 released during production.

The final product, known as "Portland cement clinker," is then mixed with gypsum and other chemicals for grinding into a fine powder known as Portland cement. All told, approximately 1.6 tons of dry raw materials are required to produce 1 ton of clinker.

Emissions Reduction Potential

It is vital to bear in mind that cement manufacturing is first and foremost a chemical process. As such it is dictated by chemical reactions requiring exact amounts of resources at specific temperatures. There exists, therefore, relatively few opportunities for significant improvement in process efficiencies. However, significant strides in operational efficiencies have been made over the past several decades and some opportunities remain.

Over the past several years, due to higher energy prices, the overall manufacturing process has moved from wet process installations to dry process preheater calciner systems. Such systems employ large single production lines which replaced the older, multiple line systems. Furthermore, the dry process reduces energy costs associated with handling wet materials. Overall, the new manufacturing processes save considerably on labor and energy costs.

At the quarrying phase, impact crushers and dropballs have been employed in place of gyratory and jaw type crushing equipment. In larger capacity quarries, large diameter blasting has been employed to save on energy costs associated with heavy machinery operations.

At the initial processing phase, significant amounts of energy are consumed in the physical reduction, mixing, and blending of materials. Recent developments in drying-grinding mills and heat recuperating preheaters (added to the available dry blending systems) have greatly reduced costs. For sulfur dioxide removal, fabric filters have been used in place of electrostatic precipitators, thus saving further on energy costs. All told, raw materials preparation accounts for about 8 percent of the energy used to produce Portland cement. Energy efficient technologies could reduce the energy use in the early stages by about 19 percent.

Clinker production, however is the most energy intensive phase of production, accounting for roughly 80 percent of energy use. At the burning stage, also known as pyroprocessing, fuel is introduced into the rotary kilns under slight pressure through a burner tip. Powdered coal or coke is the preferred fuel for economic reasons; however, No. 6 fuel oil or natural gas is frequently used. Some kilns, in fact, can lower energy costs by burning wastes such as lubricating oils, spent solvents, and chlorinated hydrocarbons. State-of-the-art technologies, such as the dry process with either preheat or precalcine and improvements in kiln refractories, kiln combustion and improved cooling techniques are estimated to reduce energy by approximately 26 percent from current average practices.

Grinding the clinker into a fine powder accounts for 11 percent of the energy use in cement production. In this stage, air separation is further used for classifying materials. To reduce energy costs associated with grinding, firms have recently employed pregrinding clinker crushers which provide savings of up to 28 percent. Higher efficiencies have also been reported with new air separators. Finally, in the storage and distribution of the final product, conveyor belt transport has reduced energy costs relative to pneumatic pumping.

Table 6-2 provides the unit operations associated with the production of cement. The table also shows the energy related processes in Btu per unit flow.

Table 6-2. Cement Production Unit Operations

Unit Operation	Electricity	Fuel	Hot Air
Crushing	75.0		
Screening & Milling	2.0		
Wet Prop & Blending	5.0		
Screening & Milling	2.0		
Slurry Mix & Blend	2.0		
Wet Kiln	10.0	1650.2	204.0
Clinker Cooler	5.0		
Prop & Blend	2.0		
Drier		270.0	
Screening & Milling	2.0		
Dry Kiln	5.0	1050.0	
Clinker Cooler	5.0		
Finish Milling	65.0		
Generated Electricity		27.6	

Source: Energy Analysis of 108 Industrial Processes. Harry L. Brown. Fairmount Press Edition: 1985.

According to the data presented in Table 6-2, the crushing and finish milling stages account for the largest fraction of electricity consumption in the cement production process. It is further apparent that the dry kiln operations represent a considerable saving over the wet kiln process.

As with lime production, it is fair to assume that any increases in process efficiency will likely be outweighed by the increased demand for cement driven by the construction industry.

As with lime, the cement production process entails numerous stages; hence, there are several areas for efficiency improvements. On a weighted average basis, it is estimated that the introduction of modern technologies at critical stages could result in a gain of 28 percent energy efficiency. With forecasted emissions placed at 596,050 in 2010, this level of savings translates into 165,214 tons.

The Utah Cement Industry

Utah contains vast amounts of the raw materials needed for Portland cement production, including high-calcium limestone, natural cement rock, high-silica quartzite and sandstone, clay and shale, iron ore from near Cedar City, and gypsum from Jurassic rock units of central Utah.

Utah hosts two producers: Holnam, Inc in Morgan County and Ash Grove Cement Company in Juab County. A third plant, which has been inactive since 1988, was subsequently purchased by Mountain Cement Company for use as a cement shipment terminal.

At its Devil's Slide plant, Holnam uses limestone from the Jurassic Twin Creek Limestone, a natural cement rock, at its 350,000 tpy wet process plant. As noted above, wet process tends to be somewhat less energy efficient; however, natural cement rock requires virtually no secondary raw materials or blending activities, thus saving energy.

Other materials used at Holnam include silica from the Triassic-Jurassic Nugget Sandstone, gypsum from the Jurassic Arapien Shale south of Nephi, and by-product iron from Kennecott Copper Corporation near Salt Lake City. The Morgan County plant uses primarily coal with natural gas backup. Of note, Holnam recently announced its intention to convert to a 700,000 tpy dry-process plant.

East of Lynndyl in Juab County, Ash Grove Cement Company's Leamington plant uses limestone from the Cambrian Dome Formation adjacent to their 825,000 tpy dry-process, coal-fired plant. Shale from the County Canyon quarry and silica from the Permian Diamond Creek Sandstone at the Nielson quarry are used at the plant. Both quarries are located within a few miles of the plant. Ash Grove also obtains iron from Kennecott slag and Nucor mill scale. Gypsum for retarding setting times is obtained from the Jurassic Arapien Shale at the T.J. Peck quarry.

In the spring of 1996, Ash Grove increased their plant capacity from 650,000 tpy. Holnam has recently indicated its intention to double its capacity from 350,000 to 700,000 tpy. Collectively, these actions signify the sustained and growing importance of cement production in Utah throughout the next century. Industry forecasters project between 2 to 2.5 percent year growth in demand throughout the United States, a rate which should easily be attained in Utah. With few substitutes, the cement industry should remain strong over the long run. Sold in a highly competitive environment, however, the industry may be subject to reorganizations, including mergers and acquisitions, which could result in long term plant closures.

D. Soda Ash

Process Overview

Commercial soda ash (sodium carbonate) is used in numerous consumer products such as soap, glass, detergents, paper, textiles, and food. About 75 percent of world production is synthetic ash made from sodium chloride. The remainder is produced from natural sources. The United States produces soda ash from natural sources exclusively.

Two methods are used to manufacture natural soda ash in the United States. The majority of production comes from Wyoming, where soda ash is manufactured by calcination of trona ore in the form of naturally occurring sodium sesquicarbonate. For every mole of soda ash created in this reaction, one mole of CO_2 is also produced and vented to the atmosphere. The other process involves the carbonation of brines; however, the CO_2 driven off in this process is captured and reused.

Once manufactured, most soda ash is consumed in glass and chemical production. Other uses include water treatment, flue gas desulferization (FGD), and pulp and paper production. As soda ash is processed for these purposes, additional CO_2 may be emitted if the carbon is oxidized. It is important to realize, however, that there is limited availability of specific information about such emissions.

Emissions Reduction Potential in Utah

CO_2 is released during production and consumption of soda ash. Soda ash is not produced in Utah; however, consumption is reported by Dyce Chemical, a distributor of soda ash which is manufactured outside of the state. Currently, Dyce is the sole distributor in the state and, according to the firm, all resources are consumed within Utah.

For soda ash consumption, 113 metric tons of carbon is released for every 1,000 tons of soda ash consumed in glass manufacturing or FGD. These latter two applications are deemed the most likely markets for future consumption in Utah.

For the glass industry, soda ash is a source of sodium oxide used as a fluxing agent in container, flat, fiber, and specialty glass manufacture to reduce the temperature at which the raw materials melt. Soda ash decomposes into sodium oxide and CO_2, which rises through the glass melt and aids in the mixing of all ingredients. Soda-rich glass is softer than other more refractory types of glass; therefore, forming is easier. The quantity of soda ash added to glass batches varies with the type of glass being manufactured and the percentage of recycled glass (also known as cullet) being used. The growing nationwide effort to recycle glass has benefitted many of the 76 domestic glass-container manufacturers because cullet substitutes for part of the raw material requirements in a glass batch, and cullet melts at lower temperatures (about 20 to 25% less), thereby reducing glass production costs. The increased use of cullet has conversely affected soda ash consumption. In 1988, the national recycling rate for all glass containers was 22 percent; however, by 1992, the rate rose to 33 percent.

Soda ash also has potential applications for flue gas desulferization (FGD). FGD is a method to reduce sulfur dioxide emissions in stack gases from the burning of fuel. Soda ash, and other soda ash-based compounds such as sodium bicarbonate and sodium sesquicarbonate, are very effective dry sorbents of sulfur and nitrogen compounds.

Compared to calcium-based compounds such as lime and limestone, soda ash-based scrubbing reagents have been proven to be more effective scrubbers because of their greater surface area that enhances the reaction with sulfur and nitrogen. However, soda ash remains more expensive and geographically restrictive than calcium-based materials. Most of the power plants that burn high-sulfur coal are located east of the Mississippi River where there are plentiful limestone quarries that can be mined more economically and transported shorter distances than soda ash produced in the West.

Finally, soda ash is increasingly used to chemically alter the pH of municipal and industrial water supplies and as a precipitant to remove impurities in brine and industrial process water. In the basic water treatment process, soda ash is added to adjust the acidity or alkalinity of water. Generally, it is added to acidic water to raise the pH and reduce the corrosivity of the water and the accumulation of mineral scale, thereby extending the life of metal pipes and equipment.

Because soda ash is not produced in Utah, there are no strategies associated with mitigation at this level. Mitigation measures must therefore concentrate on the point of consumption. Clearly, resource substitution is one strategy; however, there is no reliable data on the emissions saving from such strategies. One must assume, then, that reduction will stem from declines in output from those industries which use soda ash directly.

Manufacturing output in Utah will likely remain strong across most industries. According to the Utah Greenhouse Gas Inventory, CO_2 from the manufacturing sector will grow at just under 4 percent per year until 2010. Applying this growth rate to soda ash, one projects 608 tons of CO_2 by 2010. Any reductions from this level will likely occur as a result of materials substitution or declines in industrial output thereafter, though no accurate estimates can be made at this time.

II. Energy Sources

A. Oil and Natural Gas Production Processing

Natural gas may be released from the oil and gas system at several points, including oil wells, oil refineries, natural gas wellheads, gas processing plants, and gas transmission and distribution pipelines. Because methane is the principal constituent of natural gas (representing roughly 95 percent of the mixture) releases of natural gas lead to methane emissions.

Process Overview

As natural gas is extracted at the wellhead and moved to processing plants through gathering pipelines, leakage from flanges, meters, and valves occur. Pneumatic valves, pressurized with natural gas, will emit gas when reset. Natural gas also escapes when gathering pipelines are emptied for maintenance. After the gas reaches the processing plant, emissions also occur as a result of leakage, maintenance operations, and system upsets. System upsets result from sudden pressure spikes that prompt gas releases as a safety measure or, failing this strategy, result in a system rupture. Such events are uncommon in the U.S. oil and gas system and contribute only a fraction of total emissions.

Table 6-3. Methane From Oil and Gas Production and Transportation

Oil and Gas Production	Million Metric Tons of Methane
Natural Gas Wellheads	0.30
Oil Wells	0.04
Gathering Pipelines	1.03
Gas Processing Plants	0.68
Heaters, Separators, Dehydrators	0.17
Total	**2.23**
Gas Venting	0.83
Gas Transmission Pipelines	2.17
Distribution Systems	1.48
Oil Refining and Transportation	0.08
Total	**6.78**

Source: Emissions of GHGs in the United States 1995. Energy Information Administration. DOE/EIA - 0573(95). October 1996.

Gas Transmission and Distribution

High-pressure transmission pipelines transport natural gas from production fields and gas processing facilities to distribution pipelines. Pressure is lowered at gate stations before it enters the local distribution system. Natural gas may escape through leaky pipes and valves and also through compressor exhaust, while resetting pneumatic devices, and during routine maintenance.

Oil Refining and Transportation

During the refining process, methane leaks occur when methane and oil are separated. When oil is transferred to storage tanks at the refinery methane is emitted via vapor displacement. Methane not destroyed during flaring operations will also be vented to the atmosphere. Vapor displacement emissions occur during loading and unloading of oil barges and tankers as well.

Gas Venting

When an oil reservoir is developed for extraction there will often be associated natural gas produced at the wellhead. If the flow of associated gas is too small or intermittent to be of value the gas will be vented or flared. Associated gas with an insufficient heat content may also be vented or flared. If a site lacks the necessary gathering and processing facilities for associated gas, that gas may be vented or flared. When flared, the methane content of natural gas is converted to CO_2; when vented, the methane in natural gas is released directly to the atmosphere.

Emissions Reduction Potential

The Energy Information Administration (EIA) has compiled national statistics on methane emissions from oil and gas operations. In Table 6-3 this data is calculated in million metric tons and organized according to process or distribution.

As apparent from the table, oil and gas production and processing collectively accounts for one-third of total fugitive emissions. Gas transmission and distribution accounts for over 50 percent. Oil refining and transportation represent a mere 1 percent and gas venting just 12 percent. Overall, oil operations represent only 2 percent of the total emissions in this category. As a result, mitigation strategies should focus on natural gas operations.

According to the Utah GHG inventory, oil and gas production and distribution account for 1.3 million tons of GHG gases. Based on the percentage breakdowns above, gas transmission and distribution account for 650,000 tons; oil and gas production and processing represents 430,000 tons; oil refining and transportation translate into 13,000; and gas venting represents 160,000 tons. Strategies include fixing leaks in valves, meters, and flanges for oil and gas production and processing; recovering vented or flared gas where economically possible; repairing leaks in corroded pipeline or inadequately sealed valves as well as in compressors and pneumatic devices.

By 2010, these emissions could reach 2.2. million tons of CO_2 equivalent. Assuming a sustained rise in natural gas prices, the industry may seek efficiency improvements on the order of 5 to 10 percent, translating into 100,000 tons saved by 2010.

B. Coalbed Methane

Process Overview

Methane and coal are formed simultaneously during the process whereby biomass is converted by biological and geological forces into coal. The methane is stored in the pores (open spaces) of the coal itself and in cracks and fractures within the coalbed. As coal is mined, the pressure surrounding the stored methane decreases, allowing much of it to be released into the operating coal mine (in the case of an underground mine) or into the atmosphere (in the case of a surface mine). The methane remaining in the coal pores is emitted as the coal is transported and pulverized for combustion. There are several avenues for methane emissions from coal mines. Below are several of the more common sources.

- *Ventilation Systems in Underground Mines.* Methane in concentrations over 5 percent is explosive and presents a mortal danger to coal miners. To meet safety standards set by the Mine Safety and Health Administration (MSHA), which require levels of methane concentration to be maintained well below the 5 percent threshold, mine operators use large fans to provide a steady airflow across the mine face and ventilate the mine shaft. Typically, these ventilation systems vent substantial quantities of methane as part of fan exhaust.
- *Degasification Systems in Underground Mines.* When the volume of gas in underground mines is too high to be practically reduced to safe levels by standard ventilation techniques, degasification systems are employed. Degasification may take place before mining or may take the form of gob wells or in-mine horizontal boreholes. Methane captured by degasification systems may be vented, flared, or recovered for energy. As of 1994, some 30 degasification systems were known to be operating in U.S.mines, with 10 mines recovering gas for energy use.
- *Post-Mining Emissions.* Methane that remains in coal pores after either underground or surface mining will desorb slowly as the coal is transported (usually by train) to the end user. Because coal that is consumed in large industrial or utility boilers is pulverized before combustion, methane gas remaining in the coal pores after transport will be released prior to combustion.

Emissions Reduction Measures

Depending on the fraction of coal that is produced by relatively large and gassy mines in a state, encouraging utilization of coal mine methane can significantly reduce methane emissions. Methane released from underground mines can be recovered and sold to pipeline companies or used as a feed stock fuel to generate electricity for on-site use or for sale to off-site utilities. For pipeline sales, a coal mine would need to install gathering lines to transport the methane to a commercial pipeline. For power generation, a mine would need to install either an internal combustion engine or gas turbine, both of which can be adapted to generate electricity from coal mine methane. Most methane recovery and utilization technologies can be installed within a year.

Techniques for recovery include drilling wells before, during, or after mining. Wells drilled several years in advance of mining will generally be the most expensive, but will recover large amounts of nearly pure methane (up to 70 percent of the methane that would be otherwise emitted). Wells drilled during or after mining can also recover substantial quantities of methane (up to 50 percent of emissions), but the methane may be contaminated with mine ventilation air. While such a methane/air mixture is normally suitable for power generation, injection into pipelines would require enrichment of the gas, which may not be economically feasible.

Emissions Reduction Potential in Utah

Methane gas from coal operations may be categorized as coal-bed methane (CBM) or coal-mine methane (CMM). The former refers to methane associated with geological formations that contain coal whereas the latter refers to methane associated with actual coal production.

The economics dictate that CMM is preferred to CBM for recovery in Utah. According to the Office of Energy and Resource Planning, the majority of coal is produced in the Wasatch Plateau which contains non-gassy coal methane gas in this field does not exceed 19 cubic feet per ton of coal produced. By contrast, coal from the Book Cliffs is relatively gassy at about 451 cubic feet per ton of coal produced. During 1998, the average emission from all Utah mines was 112 cubic feet per ton of coal produced.

Methane recovery may be pursued through either a pipeline or electric power project. The former poses significant challenges due to the high cost of developing the necessary pipeline infrastructure

Table 6-4. Coalbed Methane Cost and CO_2 Reduction

	Low	Feasible or Best Estimate	Potential or High
Tons CO_2 reduced in 2010	181,483	207,409	233,335
Annualized $/ton CO2 reduced in 2010	5	5	4

to move methane from the coal bed to a large trunk, commercial pipeline. In contrast, an electric power project can more readily integrate with existing power transmission facilities.
A given mining operation would likely consider a CHP system, producing electricity for use and resale and heat for a variety of thermal applications. For a 5 MW system, capital costs are estimated at $3.6 million. Annual O&M costs and interest payments are further estimated at $773,665. Based on a representative heat rate for a typical 5 MW facility, the methane input is estimated at 63.4 million Btu per hour. Three annualized cost estimates are provided below, representing capacity factors of 70, 80, and 90 percent respectively. Table 6-4 below provides this summary information.

III. Agricultural Sources

A. Fertilizer

Process Overview

Fertilizers, whether industrially synthesized or organic, add nitrogen to soils. Any nitrogen not fully used by agricultural crops grown in these soils undergoes natural chemical and biological transformations that can produce nitrous oxide (N_2O), a GHG. Scientific knowledge regarding the precise nature and extent of nitrous oxide production and emissions from soils is limited. Significant uncertainties exist regarding the agricultural practices, soil properties, climatic conditions, and biogenic processes that determine how much nitrogen various crops absorb, how much remains in soils after fertilizer application, and in what ways that remaining nitrogen evolves into nitrous oxide emissions. Given these uncertainties, the challenge is to determine how to manipulate the nitrogen fertilizers and the time and manner in which these fertilizers are applied in order to minimize N_2O emissions.

Emissions Reduction Strategies

The technical approached for reducing nitrous oxide emissions from fertilizers include improving nitrogen-use efficiency in fertilizer applications. Improvements mean reducing excess fertilizer application by applying only the amount crops will use, and replacing industrially-fixed nitrogen fertilizers with renewable nitrogen source fertilizers.

Efficiency Improvements

All too frequently, more fertilizer is applied to a given site than can be effectively used by crops. Further, poor timing or placement often leads to additional nitrogen loss or unavailability to the crop. A major reason for excess application is the lack of simple field testing. In addition, many farmers believe that some excess may be warranted to ensure peak production given the uncertainty surrounding weather and climatic conditions.

While the direct relationship between fertilizer application rates and nitrous oxide emissions is not well understood, current estimates suggest that better fertilization practices could reduce nitrogen fertilizer use by as much as 20 percent with low risk of yield penalty and with possible input-cost savings to farmers.

Nitrogen-use efficiency can be realized through any of seven management practices and three specific fertilizer technologies. Several may be integrated into alternative agricultural systems that incorporate lower fertilizer use and also achieve energy savings by reducing the need for plowing and other energy intensive practices.

The following include specific management practices.

- *Improve fertilizer application rate.* Matching fertilizer application with specific crop requirements would reduce excess fertilization, thus producing immediate GHG reduction benefits. Soil testing, visual inspection, or plant tissue testing could allow farmers to apply nutrients more closely by following crop requirements, rather than following broad guidelines that often recommend excessive fertilization.

- *Improve the frequency of soil testing.* Due to its high cost, soil testing is usually conducted once every two to five years. New technologies, such as the "Soil Doctor," combine soil testing and fertilizer application in one system. The system has been shown to reduce application rates by as much as 41 percent per acre, though at rather high cost.

- *Improve timing of fertilizer application.* Limited studies show that emissions from fertilizer applied in the fall exceed those from fertilizer applied in the spring. With improved understanding of these processes, and implications for crop production, fertilizer timing could be adjusted to reduce GHG emissions.

- *Improve placement of fertilizer.* Surface placement and broadcasting can often result in excess or overlapping fertilizer application. Deep rather than superficial placement can reduce nitrogen loss, though such placement may not be consistent with a no-till practice.

- *Low-nitrogen fertilizer use.* Switching from fertilizers with high nitrogen content, particularly anhydrous ammonia, can reduce emissions. The rate of reduction, however, is dependent upon farmers maintaining correct levels of application and not over-compensating for the lack of ammonia found in the low nitrogen fertilizer.

- *Conservation tillage.* Alternative land tillage systems, such as low-till, no-till, and ridge-till reduce soil losses and associated loss of nitrogen contained in the soil. Tillage practices also affect the efficiency with which the fertilizer can be applied and incorporated into the soil.

- *Organic fertilizers.* Organic fertilizers can be used to replace synthetic nitrogen fertilizers where both are currently applied. With better knowledge of the nitrogen contents of various organic fertilizers, farmers can use synthetic fertilizers as a supplement.

Technical approaches include:

- *Nitrification inhibitors.* Nitrification and urease inhibitors are fertilizer additives that can increase nitrogen-use efficiency by decreasing nitrogen loss through volatilization. Nitrification inhibitors can increase efficiency by around 30 percent in some situations.

- *Fertilizer coatings.* Limiting or retarding fertilizer water solubility through supergranulation or by coating a fertilizer pellet with sulphur can double efficiency, depending on the application.

- *Reducing nitrogen release.* Techniques that limit fertilizer availability, such as slow-release or timed-release fertilizers, improve nitrogen-use efficiency by releasing nitrogen at rates that approximate crop uptake. This reduces the amount of excess nitrogen available at any given time for loss from the soil system. Slow-release fertilizer can potentially decrease the number of applications, resulting in energy and cost savings.

Estimates of savings from the above practices are complicated by the challenge of projecting field-by-field and crop-by-crop nitrogen requirements. As noted, some estimate that as much as 20 percent of nitrogen may be reduced by determining the optimal combination of practices. To a large degree, the modification of fertilizer practices is dependent on establishing the institutions and lines of communication between government agencies and farmers themselves to disseminate the knowledge of new practices.

Given the long, steady decline in Utah's agricultural sector, the likelihood of instituting many of these practices is low. Assuming that some practices will be adopted, one might assume that nitrogen emissions could be reduced by 5 percent. Based on the 2010 forecast of 127,290 tons of CO_2 equivalents, this translated into a savings of 6,365 tons.

B. Methane Emissions from Domesticated Livestock

Process Overview

The breakdown of carbohydrates in the digestive track of herbivores (including insects and humans) results in the production of methane. The volume of methane produced from this process (enteric fermentation) is largest in those animals that possess a rumen, or forestomach, such as cattle, sheep, and goats. The forestomach allows these animals to digest large quantities of cellulose found in plant material. This digestion is accomplished by microorganisms in the rumen, some of which are methanogenic bacteria. These bacteria produce methane while removing hydrogen from the rumen. The majority (about 90 percent) of the methane produced by the methanogenic bacteria is released through normal animal respiration and eructation. The remainder is released as flatus.

The level of methane emissions from enteric fermentation in domesticated animals is a function of several variables including: 1) quantity and quality of feed intake; 2) the growth rate of the animal; 3) its productivity (reproduction and/or lactation); and 4) its mobility. To estimate emissions from enteric fermentation, the animals are divided into distinct, relatively homogeneous groups. For a representative animal in each group, feed intake, growth rate, activity levels, and productivity are estimated. An emissions factor per animal is developed based on these variables, which is then multiplied by population data for that animal group to calculate an overall emissions estimate. The method for developing these factors differs somewhat for cattle as opposed to all other animals.

Ruminants, which include cattle, buffalo, sheep and goats, have the highest methane emissions among all animals due to their unique digestive system. Non-ruminant domestic animals, such as pigs and horses, have much lower methane emissions than ruminants since much less methane-producing fermentation takes place in their digestive systems. The amount of methane produced and excreted by an individual animal depends upon its digestive system (whether or not it possesses a rumen), and the amount and type of feed it consumes.

Table 6-5. Domesticated Livestock Emissions

Animal	Population	Methane Emissions (tons)	CO_2 Equivalents (tons)
Dairy Cattle	151,000	14,120.00	310,640.00
Beef Cattle	654,000	48,357.65	1,063,868.3
Buffalo	950	104.5	2,299.00
Sheep	440,000	3,872.00	85,184.00
Goats	2,129	11.71	257.62
Swine	40,000	66.00	1,452.00
Horses	34,778	688.6	15,149.2
Mules/Asses	565	13.7	301.4
Big game	232,260	6,012.00	132,264.00
Total	**1,555,682**	**73,246.16**	**1,611,415.52**

Source: Utah Greenhouse Gas Inventory.

Because emissions from cattle account for about 96 percent of U.S. emissions from enteric fermentation, they are given particular scrutiny. The U.S. cattle population is separated into dairy and beef cattle. Dairy cattle are then divided into two categories of replacement heifers (0-12 months old and 12-24 months old) and mature cows. Beef cattle are divided into six classes: 1) two categories of replacements (0-12 months and 12-24 months); 2) mature cows; 3) bulls; 4) steers; 5) steers and heifers raised for slaughter under the weanling system; and 6) steers and heifers raised for slaughter under the yearling system.

Emissions Reduction Potential

In general, methane production by livestock represents an inefficiency because the feed energy converted to methane is not used by the animal for maintenance, growth, production, or reproduction. While efforts to improve efficiency by reducing methane formation in the rumen directly have been of limited success, it is recognized that improvements in overall production efficiency will reduce methane emissions per unit of product produced. A wide variety of techniques and management practices are currently implemented to various degrees among livestock producers which improve production efficiency and reduce methane emissions per unit of product produced.

Improving livestock production efficiency so that less methane is emitted per unit of product is among the most promising and cost effective techniques for reducing livestock emissions. Specific strategies for reducing methane emissions per unit product have been identified and evaluated for each sector of the beef and dairy cattle industry. Throughout the industry, proper veterinary care, sanitation, ventilation (for enclosed animals), nutrition, and animal comfort provide the basics for improving livestock production efficiency. Within this context, a variety of techniques can help improve animal productivity and reduce methane emissions per unit of product.

Table 6-6. Performance and Emission Factors for Waste-to-Energy Project

Project MW (millions)	50
Cost per MW (million $)	2
Annual operations and maintenance cost (thousands $)	100,000
MSW (tons)	500,000
Btus (millions)	5,000,000
MWh (generated)	350,400
MWh (sold)	297,840
CO_2 produced (tons)	245,280
Utility CO_2 avoided (tons)	122,745
Landfill CO_2 avoided (tons)	20,000
Net CO_2 Emissions (tons)	102,535
Landfill CH_4 Avoided (tons)	7,008
Methane CO_2 equivalent (tons)	154,176

The existing systems for marketing milk and meat products have important influences on production efficiency and, therefore, methane emissions. Refinements to the existing marketing systems (fat versus protein pricing) hold the promise of improving the link between consumer preferences and production decisions, thereby reducing waste and improving efficiency.

Reduction Opportunities in Utah

In Utah, beef cattle account for 42 percent of all domesticated animals and dairy cattle represent 10 percent. Collectively, all other domesticated animals (buffalo, sheep, goats, swine, horses, and mules/asses) amount to 33 percent. Interestingly, the big game population (15 percent) exceeds that of dairy cattle.

Table 6-6 includes the 1993 statewide figures as well as the tons of methane associated with animal population and specie. The last column is a conversion of methane to CO_2 equivalents, based on a calculation of methane per head per year for each specie.

Based on emissions (CO_2 equivalents), the beef cattle industry represents two-thirds of all GHG emissions. A distant second, the dairy cattle industry accounts for almost one in five tons. Collectively, big game and all other animals, including non-ruminants, amounts to 15% of total emissions.

Accounting for over half the total population of livestock, the dairy and beef cattle industries represent the greatest opportunities for reducing methane emissions. For this reason, all reduction strategies will focus exclusively on these industries.

Dairy Cattle Strategies

For the dairy industry, significant improvements in milk production per cow are anticipated in the dairy industry as the result of continued improvements in management and genetics. Additionally, production-enhancing technologies, such as bovine somatotropin (bST), are being deployed that accelerate the rate of productivity improvement. By increasing milk production per cow, methane emissions per unit of milk produced declines.

Dairy industry emissions can also be reduced by refinements in the milk pricing system. By eliminating reliance on fat as the method of pricing milk, and moving toward a more balanced pricing system that includes the protein or other non-fat solids components of milk, methane emissions can be reduced. There is already a trend to reduce reliance on fat in the pricing of milk. To realize methane emissions reductions from this trend, the effectiveness of alternative ration formulations on protein synthesis must be better characterized.

Breeding options may also play an important role in reducing methane emissions. As the desirable genetic characteristics of cattle change, the breed of cattle demanded by the dairy industry will also change, possibly resulting in less cattle-related methane. In particular, the type of dairy cow that would produce higher protein products under a protein-based pricing system would also emit less methane.

To increase milk production per cow, the industry is currently using a growth hormone known as bovine somatotropin (bST). By maximizing production per cow, overall emissions should decline with increased use. However, the use of bST is somewhat controversial because of health and safety concerns for both cows and humans.

Beef Cattle Strategies

Improving productivity within the cow-calf sector of the beef industry requires additional education and training. The importance and value of better nutritional management and supplementation must be communicated. Energy, protein, and mineral supplementation programs tailored for specific regions and conditions need to be developed to improve the implementation of these techniques. The special needs of small producers must also be identified and addressed.

Refinements to the beef marketing system are needed to promote efficiency and shift production toward less methane emissions intensive methods. To be successful, the refinements to the marketing system require that the information flow within the industry be improved substantially. Techniques are required to relate beef quality to objective carcass characteristics. Additionally, the carcass data must be collected and used as a basis for purchasing cattle so that proper price incentives are given to improve cattle quality and reduce unnecessary fat accretion.

Within the beef industry, several programs are underway to achieve these objectives. Carcass data collection programs have been initiated that provide detailed data on carcass quality to participating producers. Also, a major initiative is ongoing to educate retailers regarding the cost-effectiveness of purchasing more closely trimmed beef (less trimmable fat). As these programs become more widely adopted, the information needed to provide the necessary price incentives to producers will become available.

Cow-calf productivity can potentially play a significant role reducing emissions. Increasing the rate at which cows reproduce would reduce the number of breeding cows needed. In terms of methane emissions, this is important because the breeding herd required to sustain the beef industry is significantly larger than that in the dairy industry.

Ionophore feed additives provide yet another strategy for reducing emissions. These antibiotics are mixed into feed to improve the efficiency of digestion and use. Ultimately, less feed per cow translates into less methane per cow.

A final strategy consists of using anabolic steroid implants. These implants increase the rate of weight gain in cattle, thereby decreasing the number of cows and the quantity of methane emissions per unit of beef product.

In addition to these near term strategies, several long-term options may prove viable depending on the success of ongoing research. These strategies include: 1) the transfer of desirable genetic traits among species (transgenic manipulation); 2) the production of healthy twins from cattle (twinning); and 3) the bioengineering of rumen microbes that can utilize feed more efficiently.

Competitive pressures to increase efficiency will encourage the dairy and beef industries to adopt some or all of the short-term process changes described. Since 1950, however, the number of dairy cattle in the United States has declined by over 50 percent, proving the dramatic impact that production efficiency has had on the cattle industry. According to industry estimates, methane emissions could be reduced by up to two percent per year if the above practices are employed. At this rate, 284,577 tons of $C0_2$ equivalents could be reduced by 2010 for a total of 1,271,105 tons emitted.

IV. Waste Management

A. Landfill Methane

Process Overview

Landfills remain the largest single anthropogenic source of methane emissions in the US. Municipal solid waste (MSW) landfills account for over 95 percent of landfill methane emissions, with industrial landfills accounting for the remainder. Methane is produced during the bacterial decomposition of organic material in an anaerobic (oxygen deprived) environment. The rate of landfill methane production depends on the moisture content of the landfill, the concentration of nutrients and bacteria, temperature, pH, the age and volume of degrading material, and the presence and or absence of sewage sludge. Once produced, methane migrates through the landfill until a vertical opening is reached and the gas escapes into the atmosphere.

Landfill gas produced in a sealed landfill can easily be captured by installing a gas recovery system. Landfill gas is typically 50 percent methane and 50 percent CO_2. As a medium quality gas, it can be: 1) recovered, purified, and used to generate electricity; 2) used as a source of natural gas for residential, commercial, or industrial heating needs; or 3) combusted in a flare. In addition there are several emerging technologies that may be commercially available in the future, including using landfill gas as a vehicle fuel or in fuel cell applications.

Gas recovery essentially involves the mining of trapped methane. The process consists of drilling wells into the landfill, withdrawing the gas under negative pressure, and gathering the recovered gas at a central processing center. As opposed to strategies focused on reducing the amount of degradable waste landfilled (designed to curb future emissions), methane gas recovery reduces current methane emissions. Recovering methane has other environmental and safety benefits as well, such as reducing the risk of explosions, reducing odor, and reducing emissions of air toxics and non-methane volatile organic compounds.

Landfill gas recovery projects have costs similar to those of relatively small renewable energy technologies. Profitability depends on a range of factors, including the volume of recovered methane, the price obtained for electricity or gas sales, and the availability of tax incentives. Currently, there are more than 120 fully operational landfill projects in the United States, recovering approximately 64 Bcf gas. Nearly 80 additional projects are underway and the EPA has identified another 600 profitable gas recovery projects that are currently languishing due to information, regulatory, and other barriers.

Landfill gas projects can provide many important environmental and economic benefits. The projects improve the global environment by reducing methane emissions and benefit the local environment by reducing emissions of volatile organic compounds (VOC), while simultaneously displaying emissions associated with fossil fuel use. The projects also provide a secure, low-cost energy supply that can reduce dependence on non-local energy and prevent waste of a premium energy source. Finally, such projects can provide economic benefits, such as creating jobs and generating revenues.

Emissions Reduction Potential

There are several approaches to reducing MSW, thereby reducing landfill gas emissions. These include reducing degradable wastes, recycling wastepaper products, and diverting waste to incineration facilities.

Source reduction entails diverting waste before it enters the municipal waste stream. Reduction programs generally focus on incentives for reducing product packaging, and information campaigns to promote bulk item purchase and composting.

Table 6-7. Annualized Cost of Waste-to Electricity Mitigation Strategy

	Low	Feasible or Best Estimate	Potential or High
Tons CO_2 reduced in 2010	134,904	154,176	173,448
Annualized $/ton CO_2 reduced in 2010	$47	$41	$36

Since organic wastes act as a substrate for methane-producing bacteria in a landfill, the recycling of organic wastes such as paper and paperboard, wood waste, and food waste can significantly reduce the amount of waste requiring landfill management. Recycled waste paper can also replace virgin fiber sources and, in consequence, reduce timber harvesting levels and GHG emissions.

Finally, diverting solid waste to incineration facilities also reduces the amount of MSW generated. Unprocessed MSW can be diverted to a mass burn facility where the thermal energy from the combustion is used to process steam, which can be sold directly to an institutional or industrial customer, or used to generate electrical power in a turbine. Alternatively, MSW may be mechanically processed into a more homogeneous refuse-derived fuel mixture. This mixture can be sold or burned on-site to generate steam or electricity. Although CO_2 is produced upon waste combustion, incineration saves between 0.5 and 0.6 tons of CO_2-equivalent per ton of refuse diverted relative to landfill gas emissions.

Landfill Methane Recovery in Utah

According to information provided by the Utah Department of Environmental Quality, Division of Solid and Hazardous Waste, the nine landfills that have or will soon have more than 1.1. million tons of waste in place in Utah are Salt Lake County, Davis County, Cache County, Utah County, Weber County, Washington County and Carbon County.

Though no large-scale recovery projects have been advanced to date in these counties, it is possible to estimate levelized costs for a hypothetical project. A prime candidate, particularly for counties with such high rates of growth, is a waste-to-electricity plant. The fundamental objective of such a project is to extend the life of existing landfills and to reduce the requirements of future landfills. Increasingly stringent environmental regulations will likely impose future constraints on the additional development of landfills as well.

Economic analysis suggests a minimum flow of MSW at 200,000 tons per year to justify a waste-to-electricity project. To give a sense of scale, such a flow would justify a 1 million ton in-place landfill within 5 years unless such a recovery project is built. Costs per MW for such facilities average around $2 million per MW. Annual operating and maintenance costs are estimated at approximately $100,000 per MW assuming an 80% capacity factor.

Most projects are sized to process on the order of 500,000 tons per year, roughly equivalent to 1,400 tons per day. Table 6-6 provides the cost and emissions parameters for a representative project of such scale.

Variability in MSW delivered can lead to changes in capacity factor. Though estimated at 80 percent, the project's capacity factor could range from as low as 70 percent to as high as 90 percent. The annualized costs for this range, and the estimated quantities reduced, are presented in Table 6-7.

Note that these figures do not account for revenue generated from the potential sales of electricity.

B. Municipal Wastewater

Process Overview

Emissions of methane from the treatment of wastewater occurs when liquid waste streams containing high concentrations of organic materials are treated anaerobically (in the absence of oxygen). Anaerobic processes used in the US are anaerobic digestion, anaerobic and facultative (combining aerobic and anaerobic processes), stabilization lagoons, septic tanks, and cesspools. Treatment of wastewater solids using anaerobic is the most obvious potential source of methane emissions. However, emission of significant quantities of methane from this process depends on the digester gas being vented rather than recovered or flared. Anaerobic and facultative lagoons involve retention of wastewater in impoundments where the organic materials in the wastewater undergo bacterial decomposition.

The growth of algae, which absorb CO_2 and release oxygen as a result of photosynthesis, sustains aerobic conditions at least near the surface of the lagoon. However, the bacteria deplete oxygen at the bottom of the lagoon, producing conditions suitable for methanogenic bacteria. The extent of the resulting anaerobic zone and the associated methane generation depend on such factors as organic loadings and lagoon depth. In facultative lagoons, unlike anaerobic lagoons, a significant aerobic zone persists.

Nearly 75 percent of US households are served by sewers that deliver domestic wastewater to central treatment plants. Septic tanks or cesspools treat domestic wastewater from most of the remaining households (24 percent). Anaerobic digestion is frequently used to treat sludge solids at US municipal wastewater treatment plants. However, anecdotal evidence suggests that neither recovery nor flaring of digester gas is common in the US, and equipment for recovery and flaring of such gas is poorly designed or maintained, allowing most of the methane produced to be released to the atmosphere.

Emissions Reduction Potential

Aerobic treatment requires less energy to operate and lower nutrient additions, and produces less sludge; however, anaerobic treatment generally is more efficient, adapts to a wider volumetric load range, and converts 40 to 60 percent of the emitted carbon into methane rather than CO_2. Although this methane is reconverted to CO_2 when it is combusted, when used as a fuel, it can be used to power a significant percentage of the sewage treatment system, and if refined into a liquid, can be used to fuel vehicles.

While solids must be retained longer in anaerobic reactors due to slower biodegradation rates, the necessary volume of the reactor vessel is smaller due to lower volumes of solids (due in turn to anaerobic bacteria devoting most of their energy to producing methane). Perhaps the main negative factors regarding anaerobic systems is the fact that anaerobic reactors cost about 10 percent more than aerobic reactors. Further, in situations where secondary treatment is required, anaerobically digested effluent generally requires further treatment before it can be discharged into receiving waters. This process usually involves activated sludge in which solids are agitated with air or oxygen. While activated sludge treatment is more efficient, its high energy costs make it more expensive than other filtering methods. This higher cost can be offset somewhat by reusing methane generated by the anaerobic phase(s) of treatment. This activity can have a large impact on overall operating costs, since most of the energy used in a conventional wastewater plant goes to anaerobic treatment.

Emissions Reduction Potential in Utah

In April 1999, the Salt Lake City Public Utilities department released an engineering feasibility study for cogeneration facility sited at the Salt Lake City (SLC) Water Reclamation Plant located at 1530 South West Temple.

The SLC Water Reclamation Plant is a 56-million-gallon-per-day municipal wastewater treatment plant located at 4,250 feet above sea level. Biological solids from the treatment process are stabilized in four large, heated reaction vessels known as digesters. Within these digesters, anaerobic bacteria flourish and produce combustible off-gas known as sewage digester gas.

Digester Gas

In 1998, the three 95-foot-diameter and one 100-foot-diameter digesters produced an average of about 400,000 to 440,000 cubic feet per day of gas. This digester gas is normally about 55 to 65 percent methane and, about 35 to 45 percent CO_2, along with water vapor, nitrogen and small amounts of other gases. One important other gas is noxious hydrogen sulfide (H_2S), apparently now present in the digester gas in concentrations of about 1600 to 3300 parts per million (ppm).

Digester gas is produced continuously and is currently burned in four large sewage sludge heaters and two hot water boilers to warm the contents of the sludge digesters to their 98 degrees F operating temperature. The boilers also provide the heating water necessary to warm buildings and tunnels at the treatment plant. Excess digester gas, beyond that needed by the plant, is continuously burned off in two new waste gas flares.

Energy Utilities

Electric power for the SLC Water Reclamation Plant motors, lights and equipment is purchased from Utah Power and Light (UP&L). The plant is fed from two different 46-kilovolt (kV) incoming electrical services for redundancy, as required by EPA regulations. Four UP&L electric meters serve the SLC plant, but two and the pretreatment and main plants account for 99 percent of total electrical consumption. Standby power for the pretreatment plant, about a mile away from the main treatment plant, is provided by an 800-kilowatt (kW) and an 820-kW emergency generator. These standby generators provide essential power to the influent pumps. The annual cost of electric power

Table 6-8. Summary of Recent Power Usage

	Main Plant Meter (No.1)	Main Plant Meter (No. 2)	Pretreatment Plant Area (No. 1)	Pretreatment Plant Area (No. 2)
Year	1997 (1)	1998 (3) (through May)	1997 (2)	1998 (3) (through May)
Kilowatt hours (kWh)	9,713,600	3,555,200	3,176,000	1,616,000
Peak demand (kW)	1,328	1,184	N/A	720
Average usage (kW)	1,100	994	364	452
Ratio (average-to-peak demand in percent)	83	84	N/A	63

Notes: 1. Based on a total of 368 days per 1997 billing months (or 8,832 hours)
2. Based on a total of 365 days in the 1997 billing months (or 8,760 hours)
3. Based on a total of 149 days in the first 5 months of 1998.
4. Total main plant and pretreatment plant average usage is 1,464 kW in 1997 and 1,446 kW in 1998.
Source: Salt Lake City Public Utilities communication. Dated 12 April 1999.

constitutes an important part of the cost of treatment plant operations. In 1997, SLC purchased 12,889,600 kilowatt-hours (kWh) of electric power from UP&L via the two largest plant meters. The total cost of the UP&L power was $463,174 for an average cost of $0.036 per kWH. In 1997, the yearly average electrical usage of the two larger meters was 1,464 kW.

Energy Resource

The 400,000 cubic feet per day of treatment plant digester gas is a significant energy resource. Based on a digester gas heating value of 554 Btu per cubic fool lower heating value (LHV) as tested in August 1998, this digester gas production has an equivalent fuel energy value of 9.23 million Btu per hour (Btuh).

Power Generation Potential

Using a representative engine-generator fuel efficiency of 10,000 Btu per kWh (LHV), this 1998 SLC plant digester gas could be used to continuously generate an average electrical output of 923 kW.

Plant Heating Needs

The maximum quantity of heat needed for 98 degrees F digester operation is currently about 4 million Btuh. This is based on the four existing SLC treatment plant digesters, a raw sludge flow rate of 115,000 gallons per day, and sludge thickened to 5.79 percent. This is also based on a minimum wintertime raw sludge temperature of 52 degrees F (slightly less than the minimum January 1993 low sewage temperature at the nearby Central Valley WWTP, also in Salt Lake City).

The plant's first priority is to heat the anaerobic digesters. Currently only about 40 to 45 percent of the 9.23 million Btuh fuel energy in the digester gas is needed to heat the raw sludge and the digesters in the winter. Even less heat is required during the warmer weather.

If the digester gas is used to fuel engine generators with appropriate heat recovery equipment, then adequate heat energy will be available all year for digester heating from the engine heat recovery systems. In this scenario, all digester gas is piped to the CHP facility. Sufficient heat is available, without supplemental natural gas, to heat the digesters using only the engine heat recovery system.

Existing Combined Heat and Power Facilities

In 1985, a CHP system was completed to burn the digester gas for electric power and heat for the SLC plant operations. Facilities include three 300-kW generation units, together with engine heat recovery equipment, digester gas compressors, piping, pumps, and electrical switchgear and protective devices.

Planned Facilities

The SLC Public Utilities department is currently considering four options to address methane recovery at the SLC Water Reclamation Plant. Table 6-9 provides detailed information on each proposal.

Table 6-9. Economic Comparisons of Wastewater Methane Recovery Projects

Description	Alternative A	Alternative B1	Alternative B2	Alternative C
Initial cost (construction, contingency, and engineering)	$1,900,000	$1,300,000	$600,000	$800,000
Annual operating cost (1998 dollars)	$347,000	$441,000	$347,000	$556,000
Annual operating cost savings (1998)	$209,000	$115,000	$204,000	N/A
Simple economic payback (years)	9.1	11.3	9.1	N/A
Economic payback relative to the "no CHP" diesel standby option (years)	5.3	4.3	5.3	N/A

Alternative A: (New system with two new 700-kW units)
Alternative B1: (New system with one 700-kW unit now and one 700-kW unit in 4 years)
Alternative B2: (New system with one 700-kW unit now and one 700-kW unit in 4 years)
Alternative C: (Standby diesel engines only. No CHP)

Recommendations

Alternatives A, B1, and B2 are the recommended CHP options. The alternative to select for implementation depends upon SLC's capital funding capability. The generators in these alternatives would be designed for use with a low fuel pressure delivery system and with new heat recovery equipment. The rationale is as follows:
Payback. The recommended alternatives would save SLC approximately $115,000 to $209,000 per year, in 1998 dollars, for a simple payback of 9 to 11 years. Alternative A through B both have a 10-year life-cycle cost of about $550,000 less than the "no CHP" option and a simple payback of about 5 years or less when compared to the "no CHP" option.

Financial Risk – Alternative B2 involves staging construction and capital expenditures. This option involves less initial financial risk than the larger, more expensive B1 alternative.

Economic Hedge – Alternatives A and B1 would generate about 60 to 70 percent of the SLC Water Reclamation Plant's 1998 electric power needs, thus providing economic insurance against any future increases in power costs.

Air Quality – The recommended lean-burn engines would safely comply with no required air quality standards. Moreover, the total annual exhaust emissions from the recommended alternatives would be lower that the emissions from the existing waste gas burners and boilers.

Investment Recovery – The recommended CHP system allow SLC to recover the initial CHP facility capital investment. Most of the original CHP facilities would be reused.

Waste Utilization – By converting a sewage byproduct to useful electric power, SLC will be sending a strong positive message to the community. This resourcefulness, and the net reduction in air emissions, represent important SLC commitments to the public and to the environment.

Schedule – Any of the recommendations (A to B2) could be operational within 18 to 24 months after authorization.

Each of the CHP projects is designed to recover approximately 3,200 tons per year (roughly 71,000 tons of CO_2 equivalents).Table 6-11 below shows the levelized costs per ton (CO_2-equivalents) for three levels of quantity reduced.

Table 6-10. Municipal Landfill Costs and Reduction

	Low	Feasible or Best Estimate	Potential or High
Tons CO_2 reduced in 2010	67,902	71,297	74,692
Annualized $/ton CO_2 reduced in 2010	$7	$6	$6

Part Seven
Economic Impact of Selected Greenhouse Gas Mitigation Strategies

This report considered several policy options for reducing greenhouse gas mitigation strategies, several of which involved energy-efficiency investment in end-use sectors. This section analyzes the economic impact of 13 selected mitigation strategies in the Utah residential, commercial, and industrial sectors. In particular, four strategies are considered for the residential sector, six strategies are considered for the commercial sector and three strategies are considered for the industrial sector. The premise of these greenhouse gas mitigation strategies is that investment in energy efficiency – such as more efficient lighting, motors, or heating, ventilation, and air conditioning (HVAC) – is prudent and more than pays for itself. Combined, these strategies are estimated to reduce GHG emissions from natural gas by 122,296 CO_2 (1.2 percent) under the feasible scenario and by 446,305 tons CO_2 (4.4 percent) under the potential scenario. In addition, the strategies are estimated to reduce GHG emissions from electricity by 555,946 tons CO_2 (2.5 percent) under the feasible scenario and by 3,084,634 tons CO_2 (13.6 percent) under the potential scenario. In total, the selected strategies could reduce Utah GHG emissions by 678,242 tons CO_2 in the feasible scenario and 3,530,939 tons CO_2 in the potential scenario.

Assuming a higher electricity price, investment in energy efficiency creates jobs and income growth in the Utah economy. Nevertheless, any significant reduction in electricity use will have a negative effect on the economy. The question, then, is what is the net effect? Do the benefits gained from investment in end-use energy efficiency outweigh the losses in the electricity and natural gas sectors? To answer this question, the Utah Multi-Regional Input-Output economic impact model was used to determine the empirical consequences of selected greenhouse gas mitigation strategies.

Table 7-1 outlines in broad detail the effect on the Utah economy of the investment in energy efficiency and the reduction in electricity use. All other considerations equal, then, the reduction in electricity and natural gas use has a negative effect on the economy. This is asserted qualitatively in Table 7-1 and empirically estimated in the following section. Similarly, all other considerations held constant, then the investment in energy efficiency has a positive effect on the economy. This is also asserted qualitatively in Table 7-1 and then empirically estimated in the following section. Overall, the combination of the two action programs has an unknown net effect. The Utah Multi-Regional Input-Output model is ideally suited to analyze a problem such as this. The "Economic Base" version for the Utah statewide model was chosen to offer empirical evidence.

Table 7-1. Assessing the Effect on the Utah Economy

Action	Effect on Utah Economy	Net Effect
Reduction in electricity natural gas use	Negative	
Investment in energy efficiency	Positive	
Combination of above		+/- ?

Selected end-use residential, commercial, and industrial sector mitigation strategies are identified along with fundamental assumptions concerning the effectiveness and implementation or success rates. While the 13 end-use investment strategies represent only a subset of all of the strategies considered earlier in this report, they represent a significant diversification of investment strategies. In addition, the expenditures on labor and materials to implement each of these strategies are identified and described. Finally, economic impact results are presented not only for investment in

Table 7-2. Residential Sector Investment Assumptions

Strategy	Activity	Percent Savings	Simple Payback	Feasible Implementation	Potential Implementation
Lighting retrofit	Lighting	40%	4	10%	80%
Fuel switching	Water Heating	50%	6	3%	20%
High-efficiency refrigerator	Appliance	20%	11	5%	80%
Weatherization	Heating, Cooling	30%	10	10%	70%

Table 7-3. Commercial Sector Investment Assumptions

Strategy	Activity	Percent Savings	Simple Payback	Feasible Implementation	Potential Implementation
Lighting retrofit	Lighting	25%	6	15%	95%
Lighting controls	Lighting	10%	7	10%	75%
HVAC control systems	Total Building	12%	13	10%	50%
Building commissioning	Total Building	10%	1	10%	75%
Variable-speed drive	Total Building	6%	12	5%	35%
Plug loads	Total Building	5%	1	25%	75%

energy efficiency but also for the reduction in the electric and natural gas service industries.

The Strategies in Detail

The residential sector investment assumptions are given in Table 7-2. Strategies cover high-efficiency lighting, fuel switching (electric-to-gas water heaters), premium efficiency refrigerators, and weatherization. These four strategies were chosen as examples of four broad areas of residential end-use energy efficiency improvement: lighting, fuel switching, large appliances, and total building aspects. These strategies are intended to improve the end-use efficiency of electricity and natural gas. Percent savings range from 20 to 50 percent. Payback in years ranges from 4 to 11 years. Feasible implementation or success rates range from 3 to 10 percent, while potential implementation or success rates range from 20 to 80 percent.

The commercial sector investment assumptions are given in Table 7-3. Two strategies cover

Table 7-4. Industrial Sector Investment Assumptions

Strategy	Activity	Percent Savings	Simple Payback	Feasible Implementation	Potential Implementation
Lighting retrofit	Lighting	15%	3	60%	95%
Steam system optimization	Heating, Process Heating	30%	4	15%	30%
Motors	HVAC and Processes	18%	2	50%	95%

lighting, while the remaining four strategies cover total building aspects. The six strategies are 1) high-efficiency lighting retrofit; 2) lighting control systems; 3) HVAC control systems; 4) building commissioning or recommissioning; 5) variable-speed drive motors; and 6) plug loads. These strategies are intended to improve the end-use efficiency of electricity and natural gas. Percent savings range from 6 to 25 percent. Payback in years is as low as 1 year to 13 years. Feasible implementation or success rates range from 5 to 25 percent, while potential implementation or success rates range from 35 to 95 percent.

The industrial sector investment assumptions are given in Table 7-4. These strategies cover lighting, HVAC, and processes and are all intended to improve the end-use efficiency of electricity and natural gas. The three strategies are 1) high-efficiency lighting retrofit; 2) steam system optimization; and 3) motors. Percent savings range from 15 to 30 percent. Payback in years ranges from 2 to 4 years. Feasible implementation or success rates range from 50 to 60 percent, while potential implementation or success rates range from 30 to 95 percent.

Table 7-5. Feasible Strategy Average Annual Employment

	Employment Baseline	Change in Employment	Percent Change
Agriculture	26,404	5	0.02%
Mining	9,592	(9)	-0.09%
Construction	72,124	74	0.10%
Manufacturing	130,170	33	0.03%
TCPU	55,519	(48)	-0.09%
Wholesale Trade	49,995	43	0.09%
Retail Trade	197,724	164	0.08%
FIRE	81,034	35	0.04%
Services	308,717	206	0.07%
Government	163,666	(28)	-0.02%
Total	**1,100,273**	**482**	**0.04%**

Table 7-6. Feasible Strategy Average Annual Earnings (in thousand dollars)

	Earnings Baseline	Change in Earnings	Percent Change
Agriculture	$583,270	$119	0.02%
Mining	$441,747	($447)	-0.10%
Construction	$2,239,843	$2,295	0.10%
Manufacturing	$4,258,334	$862	0.02%
TCPU	$2,157,426	($3,386)	-0.16%
Wholesale Trade	$1,587,558	$1,362	0.09%
Retail Trade	$3,014,582	$2,394	0.08%
FIRE	$2,475,541	$1,119	0.05%
Services	$7,965,133	$4,805	0.06%
Government	$4,367,555	($609)	-0.01%
Total	**$29,135,687**	**$8,561**	**0.03%**

Economic Impact Results

Economic impact results for both feasible and potential strategies are presented for the State of Utah as a whole and by major economic sector. Sectors are agriculture, mining, construction, manufacturing, TCPU, wholesale trade, retail trade, FIRE, services, and government. TCPU is short for transportation, communications, and public utilities. FIRE is short for financial, insurance, and real estate. The economic impact model presents employment and earnings impacts. These are shown in the accompanying tables as "Change in Employment" or "Change in Earnings," along with a percent change from the 1998 baseline.

Feasible Strategies

The average annual economic impact on employment of the feasible strategies is shown in Table 7-5. The feasible strategies generate an average of 482 new jobs each year. Mining, TCPU, and government showed losses. All other sectors had positive job growth. For the feasible strategies, the absolute value of the percent change is less than 0.1 percent in all sectors.

The average annual economic impact on earnings of the feasible strategy is shown in Table 7-6. The feasible strategies generated an average of almost $8,600,000 in new earnings each year. As expected, the energy-efficiency strategies result in a reduction of some electric and natural gas services jobs and earnings.

The special trades construction, wholesale trade, and architectural and engineering services show the largest increase in earnings and employment. Other sectors, however, benefit from this type of program as well. It is important to note that since the economic impacts represent average annual impact, they apply to each year of the program.

Table 7-7. Potential Strategy Average Annual Employment

	Employment Baseline	Change in Employment	Percent Change
Agriculture	26,404	18	0.07%
Mining	9,592	(41)	-0.43%
Construction	72,124	300	0.42%
Manufacturing	130,170	117	0.09%
TCPU	55,519	(280)	-0.50%
Wholesale Trade	49,995	200	0.40%
Retail Trade	197,724	603	0.30%
FIRE	81,034	127	0.16%
Services	308,717	764	0.25%
Government	163,666	(205)	-0.13%
Total	**1,100,273**	**1,623**	**0.15%**

Potential Strategies

The average annual economic impact on employment of the potential strategies is shown in Table 7-7. The potential strategies generate an average of 1,623 new jobs each year. Again, mining, TCPU, and government showed losses. All other sectors had positive job growth. For the potential strategies, the absolute value of the percent change is less than 0.5% in any of the sectors. TCPU again experience the largest reduction in employment.

The average annual economic impact on earnings of the potential strategies is shown in Table 7-8. The potential strategies generated an average of almost $24,058,000 in new earnings each year. As expected, the energy-efficiency strategies result in a reduction of some electric and natural gas services jobs and earnings. It is interesting to note the connection between the mining and utility sectors. In addition to TCPU, the mining sector also experiences a slight reduction in jobs.

The special trades construction, wholesale trade, and architectural and engineering services show the largest increase in earnings and employment. Other sectors, however, benefit from this type of program as well. It is important to note that since the economic impacts represent average annual impact, they apply to each year of the program.

Table 7-8. Potential Strategy Average Annual Earnings (in thousand dollars)

	Earnings Baseline	Change in Earnings	Percent Change
Agriculture	$583,270	$432	0.07%
Mining	$441,747	($2,181)	-0.49%
Construction	$2,239,843	$9,298	0.42%
Manufacturing	$4,258,334	$2,933	0.07%
TCPU	$2,157,426	($19,033)	-0.88%
Wholesale Trade	$1,587,558	$6,349	0.40%
Retail Trade	$3,014,582	$8,825	0.29%
FIRE	$2,475,541	$4,000	0.16%
Services	$7,965,133	$17,923	0.23%
Government	$4,367,555	($4,663)	-0.11%
Total	**$29,135,687**	**$24,058**	**0.08%**

Economic Impact Model Assumptions

An economic impact model is a quantitative representation of a local economy. The primary strength of these models is that they capture many of the inter-industry linkages that exist in the economy. The economic impact model captures the "ripple effect" caused by expenditures made in one sector of the economy and yield estimates of economic "multipliers." The economic effect of the energy efficiency investment program is the sum of the direct, indirect, and induced effect. The direct effect consists of the program costs. The indirect effect results from, for example, construction and wholesaler purchases made during the course of the program from their suppliers. The induced effect is the economic activity generated as dollars are circulated throughout the broader economy.

It is inevitable that there are several assumptions made in this type of analysis. These important assumptions are listed below and briefly described.

1) Above all, it is assumed that the fundamental economic linkages in the model remain fixed over time and do not change due to the exogenous investment in energy efficiency.

2) Since an economic impact model is best suited to analyze a small, exogenous change in the economy, extending this model to an assessment of the relatively large change required by greenhouse gas mitigation strategies would be beyond the appropriate use of the economic impact model. Therefore, we have stylized the assessment to two fundamental components of the mitigation strategies assessed in this report: 1) investment in energy efficiency in the residential, commercial, and industrial sectors; and 2) a reduction in electricity and natural gas demand and its result on the electricity and natural gas services sectors.

3) It is assumed that the reduction in electricity and natural gas consumption has an effect on the electric and natural gas services sectors. Because of fixed costs associated with electricity and natural gas infrastructure, the effect on the electric power and natural gas sectors was assumed to be less than the respective percent reduction in consumption for each fuel.

4) Other assumptions are inherent within the economic impact framework. The purchases made from the wholesale trade industry, for example, are scaled down to 20 percent. In addition, because building operators are likely to spend much of the net annual savings that stem from energy efficiency retrofits in the Utah economy, 80 percent of these savings were assumed to return to the economy in the form of increased consumption. This is assumed to be the fixed margin for the wholesaler. Economic impact analysis is a static or "snapshot" analysis. That is, the economic impact model estimates the effect of earnings and employment associated with a program, holding all else constant. Furthermore, the economic impact model does not and cannot address how an economy will adjust to this program. Nevertheless, even with the inherent assumptions and limitations, economic impact analysis provides a credible representation of an effect of a program.

Part Eight
Conclusion

Conclusions and Discussion

The most casual observer of current events cannot fail to notice the heightened attention devoted to the global issue of greenhouse gas emissions. Accounts of the issue's potential effects on the population and natural environments occupy our evening news and grace the editorial pages with increasing frequency. Indeed, barely a month passes without the media confirming long held suspicions that human activity contributes measurably to the Earth's warming. Seemingly, with each new report, yet another mind in the scientific community is won over and the public's attention is riveted once again.

It has been in the spirit of this growing scientific and public consensus that the Division of Air Quality (DAQ) and the Office of Energy and Resource Planning (OERP) has undertaken this research. Along with Phase I, the Utah Greenhouse Gas Inventory cited frequently in this study, Phase II marks the state's initial steps toward both the identification of GHG sources and the economic assessment of various GHG mitigation strategies. Specifically, it is the purpose of this study to prepare and analyze realistic policy options for reducing GHG emissions in Utah.

As noted, per capita emissions in Utah are nearly twice that of the U.S. average and the State produces significant amounts of energy for domestic use and the export market. Therefore, Utah stands to benefit tremendously from cost-effective future energy savings and associated emissions reduction. In many scenarios, the state has a unique opportunity to strengthen and diversify its economy while reducing carbons dioxide emissions and other pollutants.

This study provides engineering-economic analyses of a combination of energy efficiency and renewable energy initiatives. The research includes several options for reducing GHG emissions (carbon dioxide, methane, and nitrous oxide). These options may be ranked according to several criteria including cost, quantity reduced per measure (feasible and potential), or political or institutional feasibility. This research attempts to identify those measures for which the largest quantities of carbon dioxide are reduced, at the least cost, and with the highest degree of administrative feasibility and public receptivity.

As shown in Figure 8-1, on average, the mitigation strategies in the transportation and commercial sectors had the highest emissions reduction capacity. Unfortunately, as shown in Figure 8-2, transportation sector mitigation strategies tended to have the highest cost per ton CO_2 reduced. Because of their combination of high emissions reduction capacity and low cost, commercial sector mitigation strategies represent some of the most efficient options for achieving meaningful GHG reductions.

Figure 8-1. GHG Mitigation Strategies
Emissions Reduction

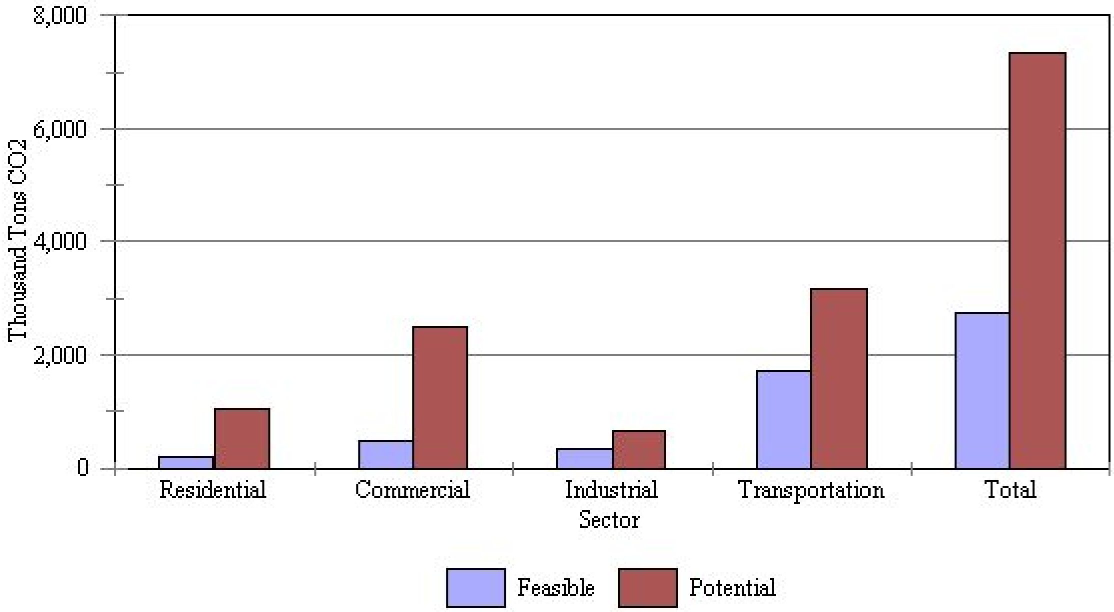
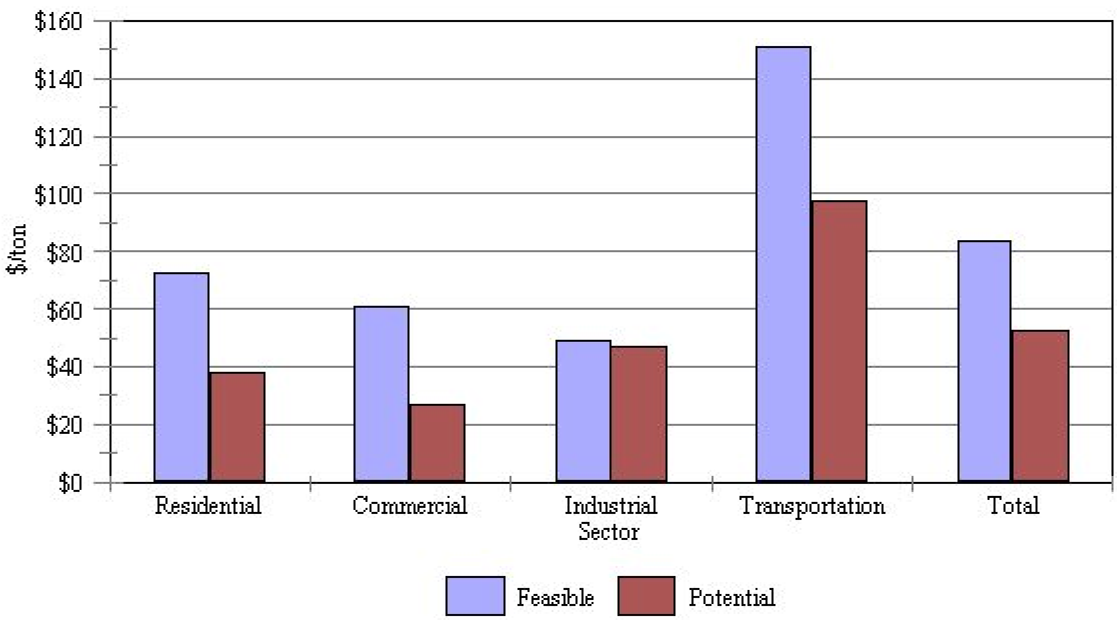


Figure 8-2. GHG Mitigation Strategies
Cost



In terms of political or institutional feasibility, there is wide variation across the many measures in each sector. By far, demand-side management programs sponsored by utilities have the longest history of application in each of the residential, commercial, and industrial sectors. Energy efficiency measures, undertaken by firms and households, are also well entrenched, popular programs.

Electricity supply technologies such as cogeneration and wind power have also enjoyed legislative support at federal and state levels for over two decades. This support will likely continue for utility-sponsored net metering, green pricing, and renewable portfolio programs. The greatest institutional hurdles, however, will likely affect the transportation sector. Fuel conversion programs will probably experience little resistance and even garner support in the years to come. However, large-scale and capital-intensive projects such as light-rail extension or heavy-rail, long-distance projects will likely encounter significant opposition and challenges.

Finally, it must be emphasized that many of the measures described herein provide "no regrets" by offering externality benefits not directly accounted for in the cost per ton calculations. For example, Utahns stand to benefit from cleaner air beyond the specific reduction of GHGs. Perhaps more importantly, the pursuit of GHG mitigation programs will greatly strengthen and diversify the Utah economy by providing firms and households with energy cost savings and, potentially, greater employment opportunities through a burgeoning energy efficiency industry.

The Role of Government Agencies and Institutions

Beyond describing the relative costs of mitigation measures, no explicit recommendations are formed regarding which measures or bundles of measures should logically be implemented. It is expected, however, that many different institutions and government agencies will ultimately be responsible for promoting measure adoption.

Federal Actions

The U.S. Senate's early ratification of the UN treaty in October 1992, and the release of the President's Climate Change Action Plan in October 1993, underscore the U.S. commitment to a National policy on global climate change that is consistent with the UN treaty. The plan consists of a two-fold strategy to commit the Nation to reducing GHGs and establish a national research agenda to enhance knowledge in areas relevant to climate change.

The national action plan essentially calls for reducing emissions to 1990 levels by the year 2000 through cost-effective domestic actions alone. Nearly 50 new or expanded initiatives encompassing all GHGs and all sectors of the economy are outlined in the plan. These voluntary programs emphasize public and private cooperation and are designed to reduce energy intensity and/or stimulate markets for new technologies. The national plan also includes the U.S. Initiative on Joint Implementation, which is a pilot program to foster experience in evaluating investments to reduce emissions in other countries.

Aside from its pivotal role in establishing the Climate Change Action Plan, and motivating state-level research on mitigation strategies, the federal government figures prominently in the support of many potential GHG reduction strategies. In the residential sector, for example, federal standards regarding appliance efficiency are key strategies for limiting emissions. Similar efficiency standards may also apply to equipment used in the commercial sector such as lighting and HVAC systems. In addition, the federal government sponsors a number of conservation programs such as Green Lights, which promotes energy efficient lighting systems. The industrial sector benefits as well from federal programs such as Motor Challenge and Steam Challenge.

It is difficult to overestimate the importance of the federal government's role in funding research and development that promotes efficient energy supply sources and end-use applications. Funding support and grants from the U.S. Department of Energy (DOE) and EPA are largely responsible for efficiency gains in various technologies such as solar, wind, biomass, and fuel cells. Perhaps more importantly, the federal government has offered tax incentives for several technologies over the past two decades.

In addition to technical and financial support, the federal government would likely assume the lead role, if necessary, in instituting market-related measures such as emissions cap-and-trade, carbon taxes, or command-and-control of GHG reduction.

State Actions

It is at the state level where most mitigation strategies will likely be identified and implemented. It is the general conviction of federal agencies that state governments are better prepared to simultaneously undertake the complex analyses of various measures and evaluate the political and institutional feasibility of implementing specific measures.

In Utah, state agencies such as the Division of Public Utilities (DPU) and the Public Service Commission (PSC) have long advocated energy efficiency practices. In compelling investor-owned utilities to offer DSM programs, state government policies have directly provided Utah's households, commercial businesses and industries with varied opportunities for saving on energy bills while improving the environment.

In addition to supporting DSM programs, state agencies have long championed supply-side strategies such as independent power projects, distributed generation, and cogeneration.

State government policies may have the greatest impact for GHG reduction in the transportation sector. Laws and regulations at the state level are necessary for establishing a number of mitigation strategies including vehicle fuel conversion and supporting infrastructure, tire inflation, enhanced I&M inspection, land-use planning, speed enforcement, traffic regulation, and mass transit projects. Of note, some of these strategies are currently being adopted by Utah.

Local Actions

Typically, local and city governments have neither the legislative latitude nor the taxing authority to promote a wide range of mitigation measures. To a larger extent, however, energy efficiency strategies adopted by municipalities frequently overlap with those advanced by state governments. Municipalities, for example, often host public utilities which generally offer DSM services to most customer classes. In addition, some utilities in Utah have sponsored renewable energy technology, most notably a wind project located in Spanish Fork sponsored by Utah Municipal Power Agency (UMPA).

Local governments promote a number of conservation programs in the transportation sector (alternative fuels, rideshare, telecommuting). States, in contrast, are at the center of most laws regarding transportation efficiency including feebates, consumption taxes, and land-use planning. Local governments are generally limited to supporting traffic improvements, speed limits, and funding for mass transit projects such as Salt Lake City's light-rail project.

Individual and Firm Actions

Household actions to limit GHG emissions are defined in this report as the willingness to participate in utility or government-sponsored energy efficiency programs and to abide by laws such as speed limits and vehicle inspections. Voluntary actions such as lowering energy consumption, the cost of which is borne by the consumer, are also considered to be crucial in gaining the maximum amount of emissions reductions.

Firm-related actions are also dependent on participation in energy efficiency programs, including actions such as telecommuting. In the case of energy-producing firms, such as electric utilities, there are additional actions that have profound consequences for energy reduction. One example is the strategic business decision of utilities to mothball coal-fired facilities or convert them to partial or full use of natural gas.

Concluding Remarks

Phase II of this research demonstrates that meaningful reductions in GHG emissions could be achieved at reasonable costs. In addition, the results of preliminary economic impact analyses suggest that these costs may be offset – or even overwhelmed -- through savings and external benefits generated by efficiency improvements to our residential, commercial, and industrial energy infrastructure. Still larger reductions in GHG emissions may likely require additional research and the development of new mitigation technologies and strategies. Regardless of which strategies – if any – are selected, it is clear from this research that solutions to the problem of rising GHG emissions will be cross-sectoral in nature and will necessitate cooperation among several public and private institutions.