Life-Cycle Assessment of Electricity Generation Systems and Applications for Climate Change Policy Analysis

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LIFE-CYCLE ASSESSMENT OF ELECTRICITY GENERATION SYSTEMS AND APPLICATIONS FOR CLIMATE CHANGE POLICY ANALYSIS

By

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Abstract

Minimizing greenhouse gas emissions may prove to be the most significant technical and political challenge facing energy decision-makers today. The U.S. electric industry contributes over one-third of domestic emissions and is arguably the most important component for effective greenhouse gas mitigation. This research uses Life-Cycle Assessment (LCA) to better understand the energy and environmental performance of electricity generation systems. The results of the LCA are used to provide an effective and accurate means for evaluating greenhouse gas emission reduction strategies for U.S. electricity generation.

LCA is performed for two electricity generation systems, a 620 MW combined-cycle natural gas plant, and an 8kW building-integrated photovoltaic system. Consideration of life-cycle energy requirements significantly reduces the net energy performance of both systems. The modern natural gas plant considered in this thesis is nominally 48% thermally efficient, but it is only 43% energy efficient when evaluated across its entire life-cycle, due primarily to energy losses during the natural gas fuel cycle. The performance of an 8kW building-integrated photovoltaic system is also reduced significantly when evaluated over its life cycle. The module's sunlight to DC electricity conversion efficiency is 5.7%; however, the system's sunlight to AC conversion efficiency is 4.3%, when accounting for life-cycle energy inputs, as well as losses due to system wiring, AC inversion, and module degradation. The meaningfulness of efficiency comparisons between technologies is

discussed and limitations are identified which make such comparisons of limited value due to the varying quality and availability of energy sources.

The LCA results drastically increase the greenhouse gas emission rate for the natural gas system. The emission rate for the combined-cycle natural gas plant life-cycle (469 tonnes CO_2-equivalent per GW_eh), was 23% higher than the emission rate from plant operation alone (382 tonnes CO_2-equivalent per GW_eh). This increase is due mainly to fuel-cycle emissions of which methane releases account for over half. There is a wide range of published estimates of fuel-cycle methane releases, with commonly cited estimates ranging from 1 to 4% of natural gas production. Because methane is a strong global warming agent, this uncertainty leads to a potential range of emission rates between 457 to 534 tonnes CO_2-equivalent per GW_eh for the studied plant.

The LCA illustrates that the PV system has a low, but not zero, life-cycle greenhouse gas emission rate of 39 Tonnes CO_2-equivalent per GW_eh. This value is higher than other nuclear and renewable systems studied previously, including nuclear fission (15 Tonnes CO_2/GW_eh), wind (14 Tonnes CO_2/GW_eh), and future DT fusion (9 Tonnes CO_2/GW_eh) technologies. The PV emission rate (39 Tonnes CO_2-equivalent per GW_eh) is insignificant in comparison to the natural gas plant (469 Tonnes CO_2/GW_eh) or a previously studied coal plant (974 Tonnes CO_2/GW_eh).

In addition to reducing emissions, effective climate change policy must also address the growing demand for electricity. This demand will likely be met with diverse energy sources, including coal, gas, nuclear, and multiple renewable technologies. Evaluating the total greenhouse gas impact from any combined electricity system is difficult, as it requires the assimilation of emission factors and generation from each technology. A ternary method of evaluation is developed that provides a simple means to compare greenhouse gas reduction alternatives. Life-cycle emissions, in particular from the natural gas fuel-cycle, are shown to add valuable insight in the evaluation of mitigation alternatives.

Three greenhouse gas mitigation alternatives are evaluated with the ternary method: 1) fuel switching from coal to natural gas for Kyoto-based compliance, 2) fuel-switching from coal to nuclear/renewable for Kyoto based compliance, and 3) fuel switching to meet the White House House's Global Climate Change Initiative. In a moderate growth scenario, fuel-switching from coal to natural gas fails to meet a Kyoto-based emission target, while fuel-switching to nuclear/renewable meets the emission objective by reducing coal generated electricity 32% below 2000 levels. The White House's Global Climate Change Initiative is shown to allow for a 14% increase in U.S. greenhouse gas emissions over 2000 levels and annual greenhouse gas emissions that are 54% higher than the proposed U.S. commitment under the Kyoto Protocol.

Acknowledgements

This work was supported in part by the Energy Center of Wisconsin, the University of Wisconsin–Madison, the Grainger Foundation, and the U.S. Department of Energy. Technical and background information for the natural gas power plant was generously provided by Max Sherman, Vice President of Project Development, on behalf of Aquila Energy. Black and Veatch Corporation provided additional technical data on the natural gas plant construction and materials. Technical and background information for the BigHorn photovoltaic system was generously provided by Joe Burdick of Burdick Technologies Unlimited. Building performance and monitoring information for the photovoltaic system was provided by the National Renewable Energy Laboratory via Sheila Hayter, Michael Deru, the High-Performance Buildings Initiative, and the PV for Buildings Task.

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1. Introduction

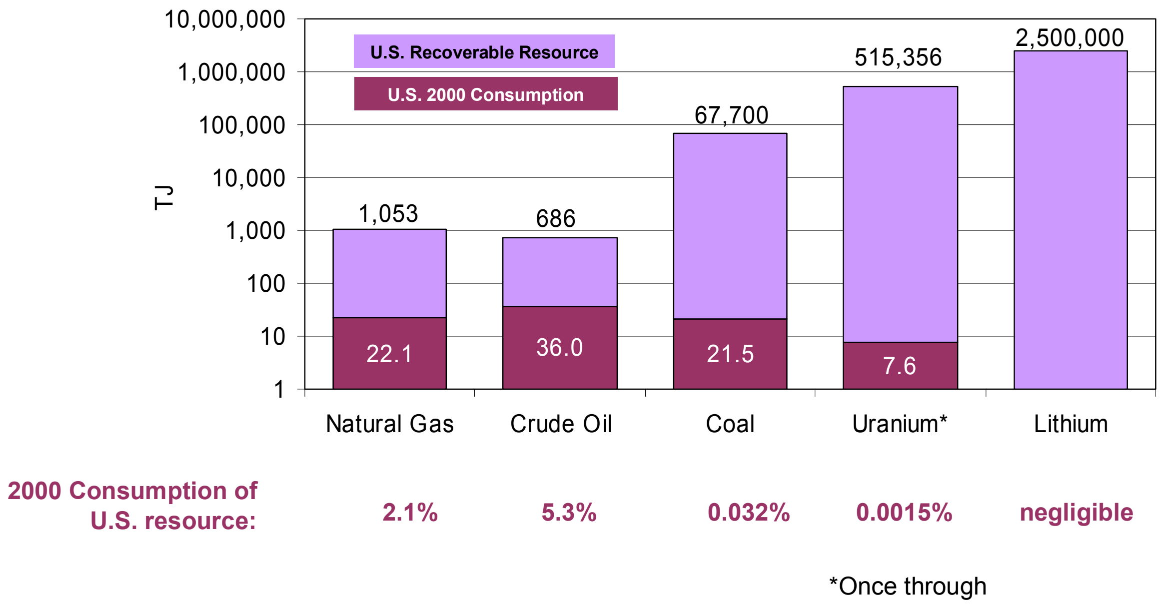
This study evaluates the life cycle of two electricity generating systems, a combined-cycle natural gas power plant (natural gas plant) and building-integrated photovoltaics (PV). The research focuses on the energy requirements, useful energy output, and greenhouse gas burden of both systems. The data, discussion, and applications presented include:

- Compilation of energy inputs and outputs using a Net Energy Analysis (NEA) for each system, and development and discussion of useful energy metrics;
- Life-Cycle Assessment (LCA) of greenhouse gas emissions for each system and calculation of life-cycle greenhouse gas emission factors;
- Comparison between systems in this thesis to previously studied systems;
- Discussion of data relevance for policy applications;
- Demonstration of metrics used in policy level analysis of fuel choices.

This research has multiple uses, and contributes to an emerging but limited body of literature. Creating a complete inventory of energy requirements and greenhouse gas emissions from the entire life cycle offers a more accurate analysis of the true energy requirements and total greenhouse impact of these two electricity systems. The prescribed data set for the natural gas plant and photovoltaic system can be compared against alternative technologies, which may prove to be integral in future fuel choices.

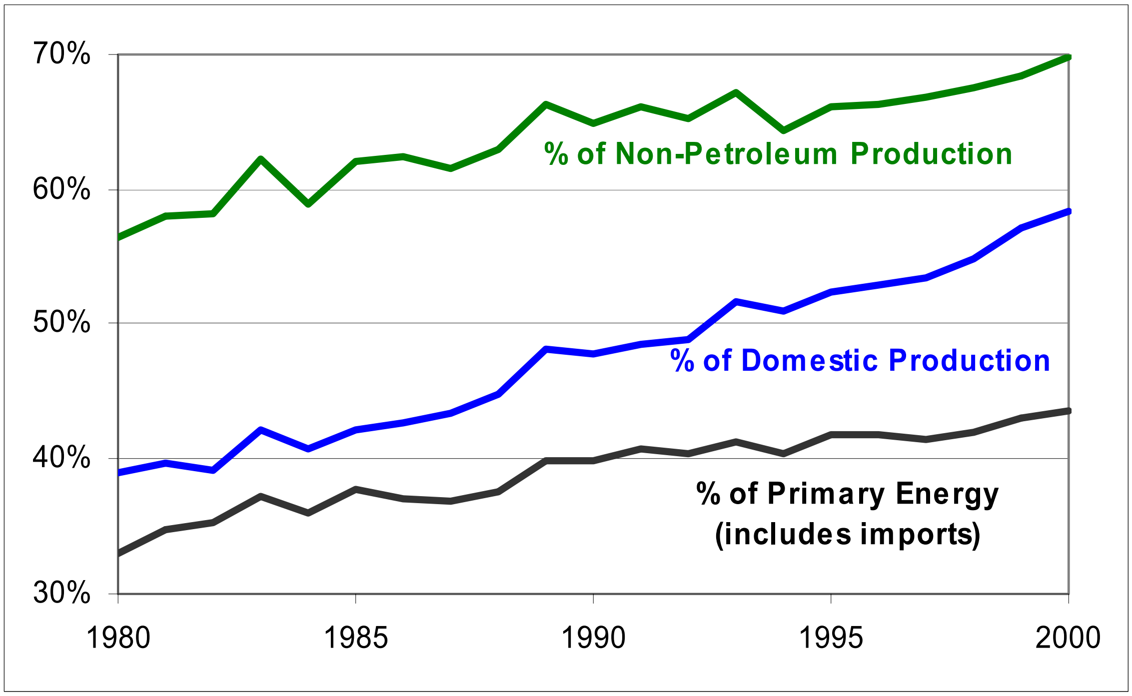
This thesis evaluates and discusses the relevance of NEA methodology when applied to electricity systems. NEA is undoubtedly a crucial method of evaluation in instances where total energy resources are scarce. Figure 1 shows current estimates of U.S. domestic recoverable fuel resources and annual fuel consumption. While short-term limitations of the combined U.S. energy resources are not established by current data, Figure 1 does illustrate the potential limitations in the U.S. supply of petroleum and natural gas.

Figure 1: U.S. Speculative Resource Estimates and Annual Consumption[1,2,3,4]



Evaluating energy efficiency using the NEA approach provides a long-term perspective on maximizing the productivity of vital energy supplies. U.S. annual energy consumption has grown by more than 25% between 1980 and 2000, while production has grown by only 7%.[3] During this same time, the portion of U.S. primary energy used to generate electricity has grown from 33% to 43%.[3] Excluding petroleum, consumption of the remaining primary energy supply to produce electricity has grown from 56% to 70% since 1980.[3] The combination of growing energy consumption and increased electrification (Figure 2) justify performing NEA for electricity systems. This method of analysis has the potential to preserve and increase domestic fuel reliance by evaluating total system efficiency.

Figure 2: Electricity generation accounts for a growing percentage of U.S. primary energy consumption.[3]



Sound energy policy requires the evaluation of environmental impacts along with resource considerations. Fossil fuel emissions of carbon dioxide (CO_2) are virtually certain to dominate the atmospheric concentration of anthropogenic (man-made) greenhouse gases over the next 100 years.[11] Despite the vast supply of domestic coal, greenhouse gas considerations may preclude our long-term reliance on this resource. Conversely, the value of greenhouse gas mitigation offered through nuclear power may justify an increased investment in the aging nuclear infrastructure and waste storage. The methods prescribed in this research provide for accurate calculation of the life-cycle greenhouse gas impact of electricity systems.

The ultimate goal of this research is to provide policymakers with meaningful metrics for effective evaluation of greenhouse gas control strategies. The electric industry is arguably the most important component for effective greenhouse gas mitigation. The U.S. electric industry contributes over one-third of domestic emissions annually.[5] Because of this impact, the development and use of accurate life-cycle emission factors for electricity generation is vital to informed decision making.

In addition to reducing emissions, effective climate change policy must also address the growing electricity demand. This demand will likely be met with diverse energy sources, including coal, gas, nuclear, and multiple renewable technologies. Evaluating the total greenhouse gas impact from any combined electricity system is difficult, as it requires the assimilation of emission factors and generation from each technology. The methods and ternary illustration developed herein offer a simple method for evaluating various emission scenarios from the U.S. system with continued growth in electricity consumption.

2. Background

Net Energy Analysis compares the useful energy output of a system to the total energy consumed by the system over its life cycle. By doing so, NEA assesses the overall efficiency at which an energy system can generate electricity. This consideration has growing importance in the United Sates, where a quarter of the world's energy is consumed. The U.S. and the State of Wisconsin issued long-term energy plans in 2001. [6,7] Both plans projected continued growth in energy consumption and called for an expansion of electricity generating infrastructure. According to the national report, "our nation's most pressing long-term electricity challenge is to build enough new generation and transmission capacity to meet projected growth in demand."[6]

The U.S. has historically become more energy-efficient in terms of energy consumed per economic output as shown in Figure 3. Despite this continuous improvement, total energy consumption has steadily increased as shown in Figure 4. The fuel choices utilized to meet our growing energy use demand critical evaluation. Available resources and infrastructure are primary concerns; however, resources must be evaluated alongside associated environmental impacts. Of these, minimizing greenhouse gas emissions may prove to be the most significant technical and political challenge facing energy decision-makers today. A significant reduction in greenhouse gas emissions will likely require both improvements in end-use efficiency and an increased reliance on lower emitting technologies.

Figure 3: The U.S. steadily improved energy efficiency from 1950 to 2000.
From Energy Information Administration[3]

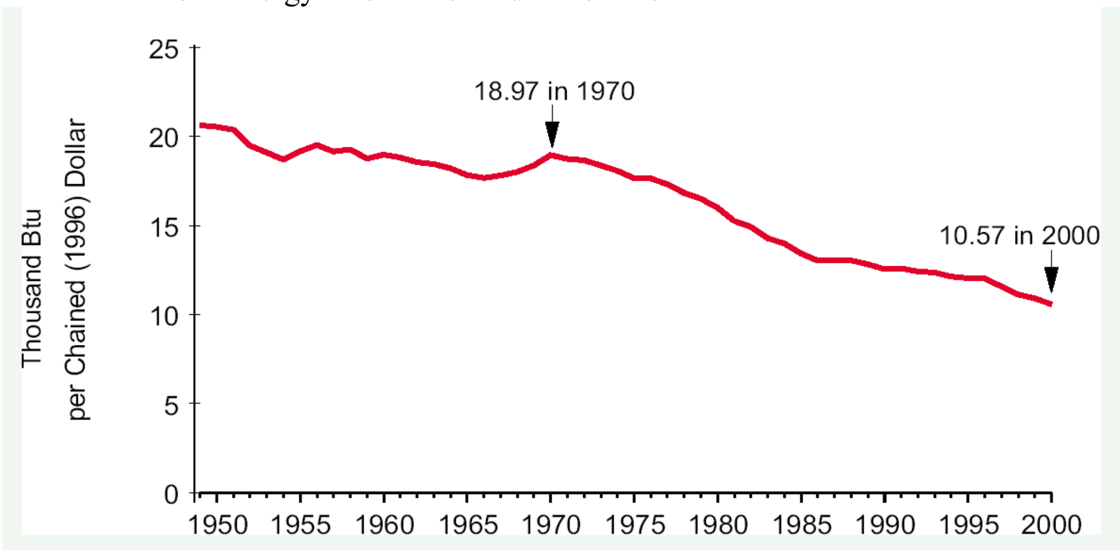
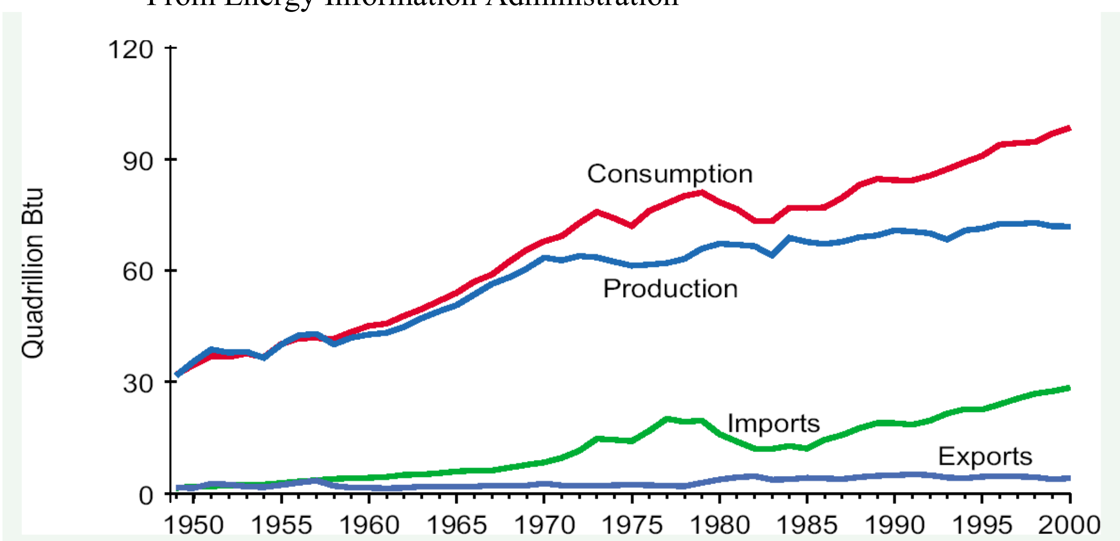


Figure 4: U.S. energy consumption increased dramatically between 1950 and 2000.
From Energy Information Administration[3]



Ongoing research continues to strengthen the correlation between greenhouse gas emissions and global climate change. “It is not a question of whether the Earth’s climate will change, but rather when, where and by how much,” states Robert Watson, Chairman of the Intergovernmental

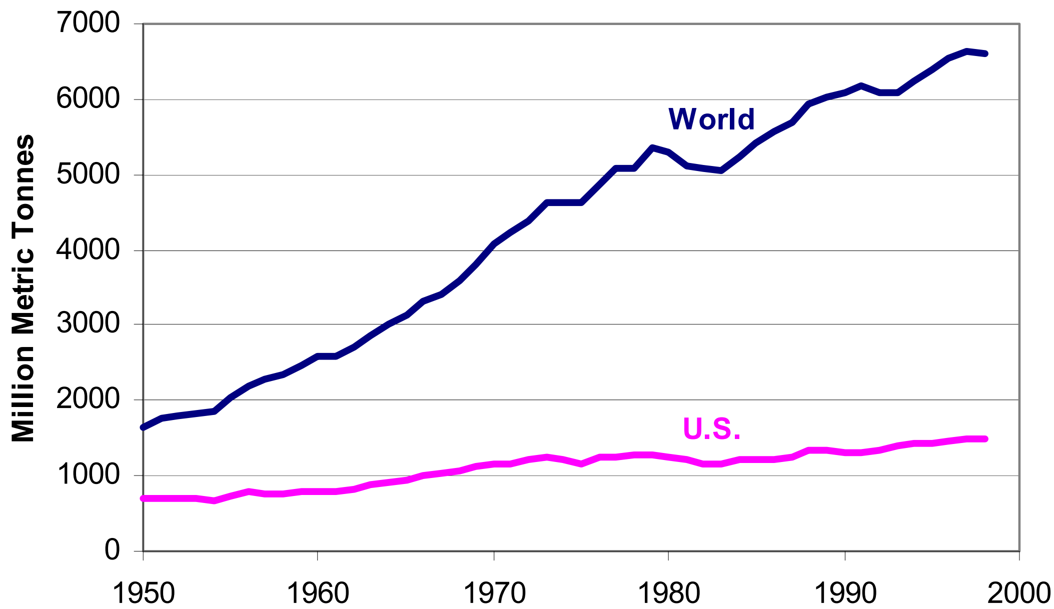
Panel on Climate Change (IPCC).[8] Recent observations confirm the warming of each major component of the earth's climate: atmosphere, oceans, and cryosphere.[9,10] Most of the warming of the last 50 years is believed to be the result of increased greenhouse gas concentrations.[11]

Greenhouse gases allow incoming short-wave solar radiation to penetrate the atmosphere, but absorb the infrared radiation reflected back by the Earth's surface. The infrared radiation is trapped in the atmosphere, causing air temperature to rise. Emissions of greenhouse gases from human sources (anthropogenic) have been accelerating since the industrial revolution, in proportion to the growing use of fossil fuels. While oceans and terrestrial plants regulate concentrations of CO_2 in the atmosphere, these natural processes absorb only about half of the anthropogenic emissions.[12,13] The excess accumulates in the atmosphere, which has resulted in a 28% increase in CO_2 concentration from levels that were relatively stable for the past 1,000 years.[14]

The IPCC estimated an increase in the global surface temperature of 0.6^{o} C has occurred over the last century, and projects air temperatures to warm an additional 1.4^{o} to 5.8^{o} C by 2100. A sea-level rise between 9 and 89 cm is projected over the same time period.[11] The climatic change is expected to prompt a host of adverse effects depending on the geographic location, including increased floods and droughts, damaged ecosystems, and increased heat-stress mortality.[15]

Minimizing the risk of climate change will require a sustained global effort to limit atmospheric greenhouse gas concentrations. The U.S. produces almost one-quarter of the world's anthropogenic greenhouse gas emissions annually (Figure 5), and is therefore an essential participant in greenhouse gas reduction efforts.

Figure 5: Global and U.S. Annual Anthropogenic Carbon Emissions[16,17]



In response to scientific concern over climate change, the United Nations (UN) and the World Meteorological Organisation (WMO) established the IPCC in 1988.[18] The objective of the IPCC is to accumulate data on climate change and provide scientific advice to policy-makers. In December 1990, the UN established the Intergovernmental Negotiating Committee (INC) which in turn developed the Framework Convention on Climate Change. On June 4, 1992, more than 160 countries adopted this treaty at the "Earth Summit" in Rio de Janeiro, Brazil.[13] The Framework aims "to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."[19]

The convention requires all participating nations to keep an inventory of greenhouse gas emissions, and to undertake policies and measures to limit greenhouse gas emissions. The convention further requires developed industrial countries (Annex I countries) to "(return)…to their 1990 levels these anthropogenic emissions of carbon dioxide and other greenhouse gases".[19] In 1993, President Clinton committed to stabilizing U.S. emissions of greenhouse gases at the 1990 level by the year 2000, using voluntary measures.[20] The Climate Change Action Plan consists of federal initiatives designed to reduce or avoid greenhouse gas emissions.[21] Despite this effort, the U.S. continued to increase greenhouse gas emissions (See Figure 5), as did many other Annex I countries.[13]

The Framework Convention did not address the issue of reducing greenhouse gas emissions after 2000. In order to develop a strategy for post-2000 climate control, the first Conference of Parties (COP) met in Berlin, Germany, in 1995.[21] The following year, COP-2 was held in Geneva, Switzerland, and agents agreed to develop binding emission limitations for Annex I countries at COP-3 in Kyoto, Japan.[13] The Kyoto Protocol to the Framework Convention was adopted December 11, 1997.

The Kyoto Protocol established quantified emission reduction targets for the Annex I countries that collectively reduced greenhouse gas emissions to 5% below 1990 levels. Each Annex I country received a specific reduction target, for which they are responsible. The target is in reference to the average of that nation's emissions over the 5-year period from 2008-2012 (commitment period) and ranges from 90-110% of 1990 levels. The U.S. was assigned the commitment of reducing emissions to 93% of 1990 levels. [13]

The U.S. administration signed the Kyoto Protocol in 1998, but did not legally commit to implementation. The U.S. Constitution requires the "advice and consent" of the Senate to enter into a treaty agreement. Prior to the signing of the Kyoto Protocol, the Senate passed the Byrd-Hagel Resolution, which specified that the U.S. should not be a signatory to United Nations Framework Convention on Climate Change without scheduled commitments from developing Countries, or if it would result in serious harm to the economy of the United States.

The U.S. retreated from the Framework Convention on Climate Change negotiations in March of 2001, with President Bush citing harm to the U.S. economy and protesting the Kyoto Protocol's exemption of developing countries.[22] In February of 2002, President Bush proposed a new approach to climate change policy which would use as its benchmark greenhouse gas intensity in terms of tons of greenhouse gas emissions per dollar Gross GDP. Bush's Global Climate Change Initiative set as a national goal the reduction of greenhouse gas intensity of the U.S. economy by 18% between 2002 and 2012.[23]

Current U.S. Policy to address climate change consists of voluntary energy efficiency programs, research and development investments, tax incentives for renewable energy, appliance efficiency standards, and emission reduction requirements for federal buildings and transportation fleets. [24] The National Energy Policy Development Group issued a report in May 2001 which recommended extending and expanding renewable energy tax credits and offering tax credits to combined heat and power plants and landfill methane projects. The National Energy Policy report recommended funding clean coal research and promoting new construction of nuclear capacity.[6]

The U.S. Department of State submitted the third U.S. communication under the UNFCC to the United Nations in May 2002.[25] The Climate Action Report reviewed current U.S. climate change policy including the National Energy Policy[6] and the White House Climate Change Initiative.[26] The report acknowledged that "greenhouse gases are accumulating in Earth's atmosphere as a result of human activities, causing global mean surface air temperature and subsurface ocean temperature to rise." The reports projected a 43% increase in U.S. greenhouse gas emissions by 2020 in the absence of new mitigating measures. Potential U.S. impacts cited in the report include disappearance and fragmentation of eco-systems and exacerbation of threats to infrastructure in climate sensitive areas.

Multiple proposals currently in the 107th Congress are aimed at addressing climate change. The Climate Change Strategy and Technology Innovation Act[27] requires development of a U.S. Climate Change Response Strategy. The Climate Change Risk Management Act[28] requires development of a national strategy to manage the risks posed by potential climate change. The Foreign Relations Authorization Act[29] urges the U.S. to resume participation in Kyoto Protocol negotiations. Greenhouse gas emissions reductions from electric power plants are called for in The Clean Power Act[30], The Clean Smokestacks Act[31], and The Great Smoky Mountains Clean

Air Act[32]. Additional proposals call for greenhouse gas reporting, research funding, carbon sequestration, and promote lower carbon emitting technologies.

3. Literature Review

3.1. History

In the 1960's, the U.S. Department of Energy conducted "fuel cycle" studies that evaluated energy requirements and included limited estimates of environmental releases.[33] Popular use of Net Energy Analysis (NEA) for energy systems was prompted by the oil shortages of the early 1970s. Chapman published the first modern NEA of an energy system in his 1974 paper, "The Energy Cost of Fuels".[34] Daniel Spreng published the most comprehensive book on the subject in 1988, entitled *Net Energy Analysis and the Energy Requirements of Energy Systems*.[35] Spreng credits Howard Odum with initiating the modern concept of NEA in Odum's 1971 book *Environment, Power, and Society,*[36] after which several papers were published on the manufacturing of various materials.[37]

3.2. Methods

The two methods for performing a NEA are Input/Output (I/O) and Process Chain Analysis (PCA), described in detail in Section 4. The I/O method correlates dollar cost to energy consumption, called energy intensities. The first I/O energy matrix was published by Herendeen in 1973.[38] This matrix was updated in 1981 and 1985 by the Energy Research Group at the University of Illinois.[39,40] The most current I/O matrix (2002) is maintained by the Green Design Initiative at Carnegie Mellon University.[85]

The PCA method provides an inventory of direct energy consumption throughout a process. This method of accounting for energy was first formally described by Chapman in 1974.[41] In 1978, Bullard published a paper on combining I/O and PCA methods entitled "Net Energy Analysis: Handbook for Combining Process and Input-Output Analysis".[42] Methods for applying the NEA methodology to energy systems are provided by Spreng[35] and Perry.[43]

3.3. Applications to Electricity Generation Systems

The NEA of a system, in conjunction with the evaluation of the system's environmental impact, is commonly referred to as Life-Cycle Assessment (LCA). A popular LCA application is the evaluation of electricity generating systems and development of greenhouse gas emission factors. Several dozen of these LCA studies exist covering every conventional power source.[37] Multiple studies have been published on natural gas power plants. Spath and Mann[44] at the National Renewable Energy Laboratory performed a life-cycle study on a system similar to that studied by Meier and Kulcinski[45]. Results from earlier natural gas studies were published by Rasheed,[46] Waku,[47] Vattenfall,[48] Uchiyama,[49] Dones,[50] Macdonald,[51] Audus,[52] Proops,[53] Wilson,[54] and Martin.[55]

Several life-cycle studies of PV systems have also been published, including reports by Alsema,[56,57] Nieuwlaar,[58] Oliver,[59] Keoleian,[60] Kato,[61] Dones,[62] Voorspools,[63] Frankl,[64] Martin,[55] Yamada,[65] and Tahara.[66] The studies by Alsema, Kato, Keoleian, Martin, Yamaada and Tahara perform life-cycle assessment on thin-film amorphous silicon PV as prescribed for this research. These studies consider manufacturing of the module and balance of system, but many neglect other life-cycle components (e.g., installation, maintenance, disposal) as defined in Section 6.

3.4. Metrics

There is no consensus within existing literature for expressions used to summarize the NEA results. The time needed for a system to generate useful energy output equal to its life-cycle energy input (Energy Payback Time) is often reported. Three other energy ratios are also applied: electrical output per primary energy input, primary energy input per electrical output, and electrical output per thermal input excluding direct fuel. Spath and Mann[44] offer two additional metrics which subtract the primary inputs from the electrical output and compare to the fuel input. Metrics used exclusively in PV studies include energy per m^2 of PV module manufactured, energy per kW of rated PV power, and net solar efficiency ((electrical energy output – non-solar energy input) / solar energy input). Additional explanation, discussion, and naming conventions for these metrics are provided in Section 4.2.

Most NEA studies on electricity systems include estimates of greenhouse gas emissions. The greenhouse gas impact is most frequently expressed in terms of mass of carbon dioxide equivalent emitted per unit energy produced (e.g. kg CO_2-equivalent per kWh). Environmental benefits are also expressed as the total emissions avoided (e.g. kg CO_2-equivalent avoided) which require estimating the emission rate for the existing electricity generation mix or other baseline scenario. Frankl's study[64] compares the ratio of the emissions avoided per emissions produced.

3.5. Policy Applications

Few LCA studies are credited with contributing to environmental policy or regulatory development.[67] Elcock[67] reviewed nine LCA studies and reported that two were used in the development of regulation or policy, three were used to respond to regulation or policy, and four had no direct link to regulation or policy. The importance of LCA in evaluation of policy options is also discussed by Ross[68] and Audus[52]. Audus[52] concludes that LCA in conjunction with cost benefit evaluation could become the basis of comparison for non-fossil sources of electricity, but further work is needed to understand how best to apply it.

This dissertation uses LCA to evaluate fuel substitution strategies aimed at reducing greenhouse gas emissions within the electric industry. Multiple studies with similar objectives are discussed in Section 6.4.B. Analyses of electricity generation options for global carbon mitigation are provided by Ito,[69] Hoffert,[70] Roehrl,[71] Hammons,[72] and Knapp.[73] Similar studies that more specifically address fuel substitution and greenhouse gas policy for U.S. electricity generation are performed by Hayhoe,[74] Kydes,[75] Bernow,[76] and the Wisconsin Department of Natural Resources.[77] Studies that evaluate fuel switching alternatives for greenhouse gas mitigation in foreign countries are provided by Masjuki,[78] Syri,[79] Chedid,[80] Wang,[81] and Zhang.[82]

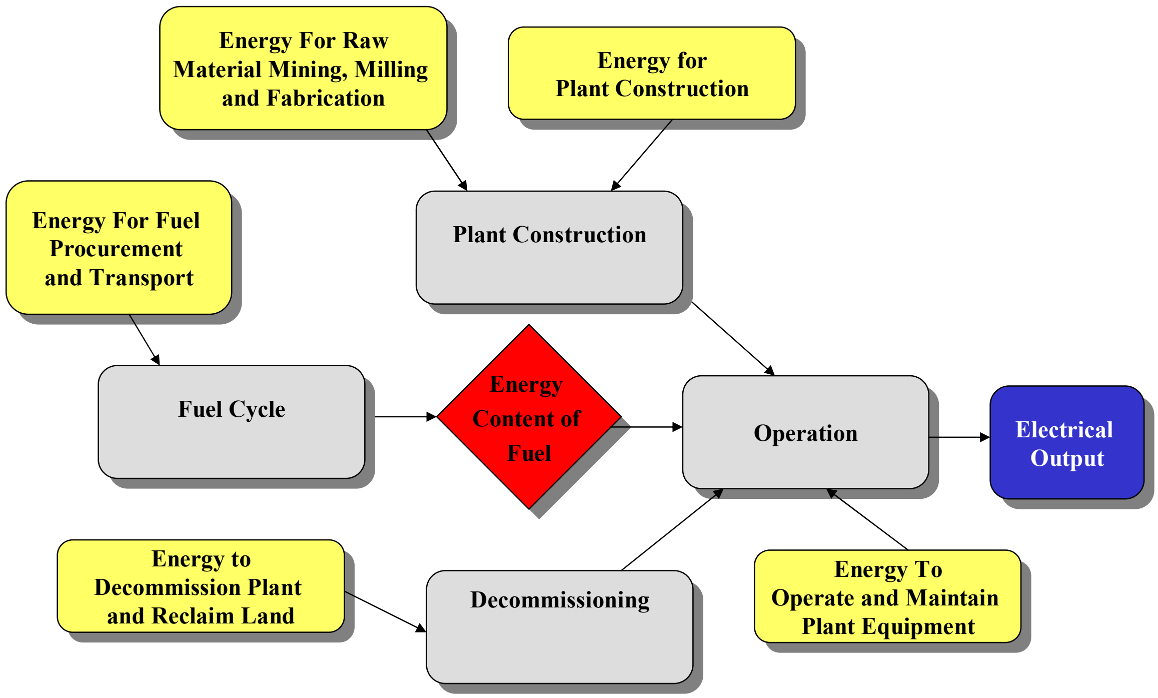
4. Methodology

4.1. Net Energy Analysis

This dissertation performs a NEA for two electricity generating systems: a combined -cycle natural gas power plant and a building integrated photovoltaic system. The NEA is performed by estimating the energy requirements for each phase of the life cycle and comparing these “energy inputs” to the useful electrical output of the plant.[83]

This study employs a life-cycle approach, which evaluates the entire system from the initial gathering of raw materials to the point at which all materials are returned to the earth.[33] Therefore, unlike conventional approaches that only consider facility operation, the life-cycle approach includes the “upstream” processes such as the mining of raw materials, and “downstream” processes such as plant decommissioning. The NEA estimates the energy required for each of the life-cycle phases along with the useful electrical output (See Figure 6 for an illustrative example).[84]

Figure 6: Net Energy Analysis requires the estimation of energy inputs from each of the life-cycle phases along with the useful electrical output.



For a natural gas plant, the output energy is a simple calculation based on the average electrical power output of the plant, average capacity factor, and plant lifetime. The output energy for the PV system may be based on actual performance data, or estimated using the average solar insolation rate and the module conversion efficiency.

Energy inputs are estimated by PCA and I/O methods.[35] PCA evaluates the material and energy flows for each process within the system life cycle. This methodology relies on actual data for the primary energy expended during each step, such as the electricity consumed (converted to primary energy) in manufacturing the PV module, or the diesel fuel consumed in transporting the completed modules to the building site. The PCA method requires defining a system boundary for analysis. Such an analysis cannot practically consider the entire economy (i.e., the system considered has defined boundaries) and is therefore subject to truncation error, a slight underestimation of energy inputs.[35]

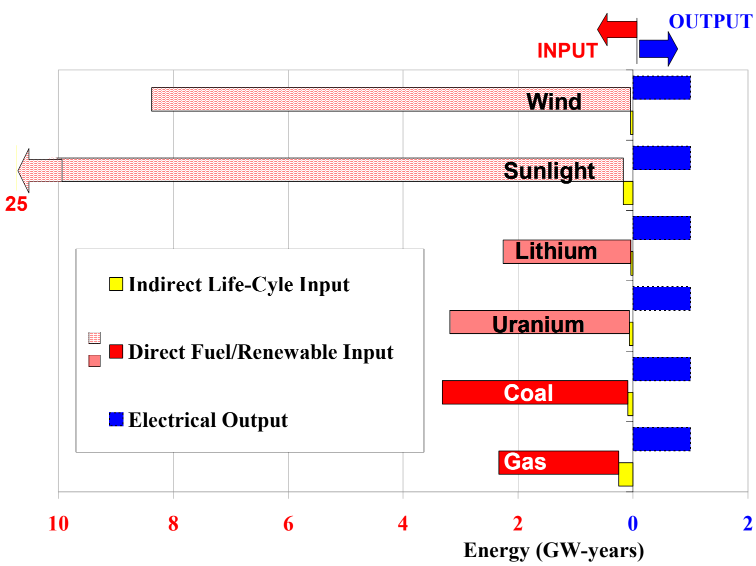
The I/O method correlates dollar cost to energy use. The input/output model used in this study divides the U.S. economy into distinct sectors.[85,86] These sectors are the basis for a matrix, within which the cost and energy requirements are distributed.[87] Based on the cost of goods or services procured from a given sector, the model estimates the total energy consumed directly and indirectly throughout the economy. The I/O method averages prices across sectors and therefore introduces inaccuracies when the actual energy intensity of a process differs from the sector average.

In most cases, a combination of PCA and I/O is the most practical approach to net energy analysis.[35] PCA is highly reliable with small truncation errors and will therefore be used whenever practical. However, for many processes, data on energy consumption is not adequately recorded. In these cases, the availability of cost data allows for evaluation using the I/O method. The I/O method will generally be relied on to evaluate portions of installation, operation, maintenance, and decommissioning. I/O data will be taken from the Economic Input-Output Life Cycle Assessment (EIOLCA) database.[85] The EIOLCA model is based upon the 1992 Department of Commerce's 485 x 485 commodity input-output model of the U.S. economy and provides the most current and comprehensive I/O model.[86] Energy intensities (energy consumed / dollar) are adjusted using the consumer price index to account for inflation.

4.2. Metrics

After completion of the net energy analysis, the energy data are compiled into metrics used for comparing technologies. Figure 7 provides a summary of net energy requirements from this work and work by White and Kulcinski.[88,89,90] Section 6.1.C discusses the importance of the different types of energy inputs for consideration in this research.

Figure 7: Summary of Life-Cycle Net Energy Analysis for Renewable, Nuclear, and Fossil Plants



	Life-Cycle Energy Efficiency	Energy Payback Ratio
Wind	12%	23
PV	4%	6
DT Fusion (projected)	44%	27
Fission	31%	16
Coal	30%	11
Gas CC	43%	4

Two metrics are considered in this study: Life-Cycle Efficiency (LCE) and Energy Payback Ratio (EPR). LCE (Equation 1) is the ratio of the useful electrical output to the sum of the thermal input of fuel supplied both at the plant and throughout the life-cycle.

$$\textbf{Life-Cycle Efficiency} = \frac{\textbf{Lifetime Electric Output}}{\textbf{Direct Energy Inputs + Indirect Life-Cycle Input}} \qquad \textbf{Eq. 1}$$

As an alternative to the LCE metric, the Energy Payback Ratio (Equation 2) will also be used to compare technologies. The EPR is a comparison of the useful electrical output to the life-cycle energy inputs, but excludes the energy content of the fuel used directly for generating electrical energy (e.g. sunlight or wind).

$$\textbf{Energy Payback Ratio} = \frac{\textbf{Lifetime Electric Output}}{\textbf{Indirect Life-Cycle Input}} \qquad \textbf{Eq. 2}$$

The LCE and EPR metrics compare technologies from an energy standpoint only. Section 6.1.C will evaluate the applicability of these metrics in comparing widely differing technologies. In addition, the relevance of these metrics for policy applications will be considered.

The NEA provides a convenient and accurate basis for estimating greenhouse gas emissions by supplying an inventory of fuels consumed throughout the life cycle. The relationship between the type and quantity of the fuel consumed and the resulting greenhouse gas emissions is well established. Greenhouse gases are accounted for in this study in terms of CO_2-equivalent emissions. Methane and nitrous oxide are respectively 21 and 310-times stronger global warming agents (per unit mass) than CO_2, based on 100-year global warming potentials as recommended by the IPCC.[5] For example, 1 tonne of methane emissions has the same long-term greenhouse impact as 21 tonnes of CO_2-equivalent emissions.[14]

The total emissions from each technology are normalized relative to the electricity generated (Equation 3), providing an emission rate in terms of tonnes CO_2-equivalent emitted per gigawatt-hour of net electricity produced (Tonnes CO_2/GW_eh). Net electricity production excludes recirculated plant power used for plant operation.

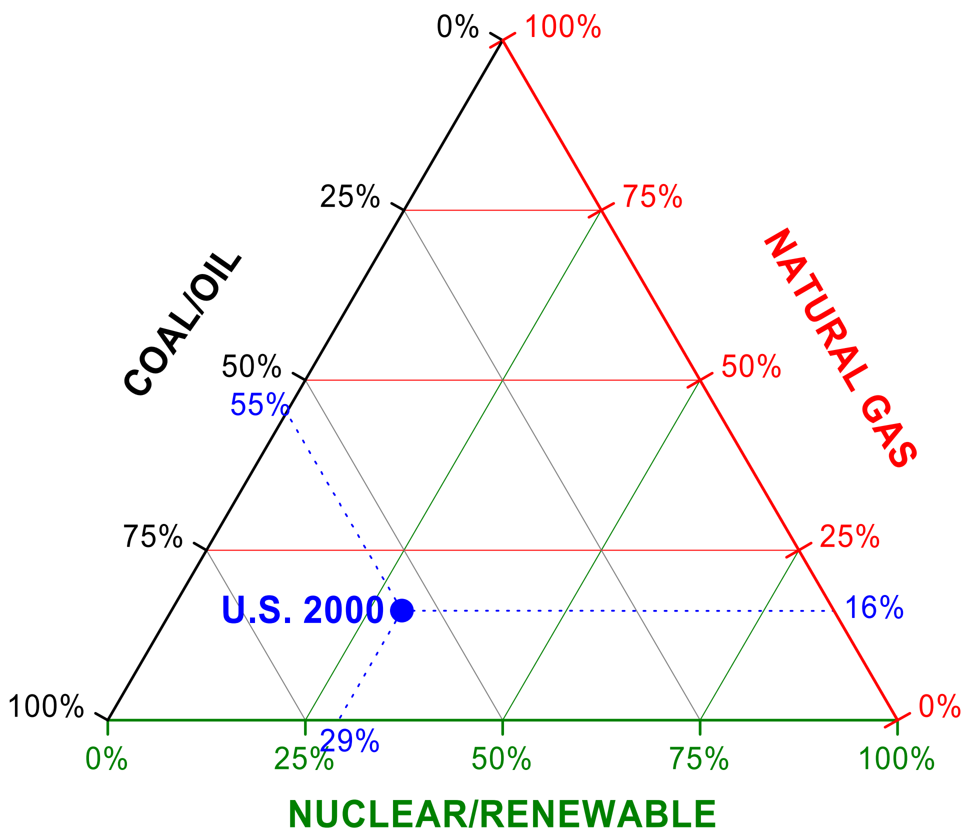
$$\textbf{Life-Cycle Greenhouse Gas Emission Factor} = \frac{\textbf{Life-cycle } \mathbf{CO_2} \textbf{ – Equivalent Emission (Tonnes)}}{\textbf{Lifetime Net Electrical Output } \mathbf{(GW_eh)}} \qquad \textbf{Eq. 3}$$

4.3. Policy Applications

Section 6.4 will illustrate the use of life-cycle emission rates in the evaluation of policy issues. Historically, continuous improvements in overall energy efficiency have occurred simultaneously with a net growth in U.S. energy consumption (See Figures 3 & 4). Based on this trend, it is unlikely that greenhouse gases emissions can be reduced without a shift toward less carbon intensive technologies. In question is how the U.S. electric industry can reduce greenhouse gas emissions while meeting a growing demand for electricity. The answer undoubtedly points to a shift away from coal and toward natural gas and nuclear/renewable technologies. To answer this question quantitatively and graphically, a ternary method and illustration is developed in this section. The ternary method presented here is valuable because it quantifies the shift in generation required to meet emission targets.

The ternary plot has three axes representing the contributions from coal, natural gas, and nuclear/renewable technologies used for generating U.S. electricity. The axes values range from 0 to 100% and represent the percentage of electricity generated from three groups of technologies: coal/oil, natural gas, and nuclear/renewable. Each point represents a unique mixture of generating technologies. Figure 8 illustrates the data point representing U.S. electricity generation in 2000. Contributions from natural gas (16%) are read horizontally to the right, nuclear and renewable are contributions (29%) are read toward the lower left, and coal contributions (55%) are read toward the upper left. At every point the summation of values of the three axes add up to 1.0 or 100%.

Figure 8: The fraction of U.S. electricity generated from coal and oil was 55% in 2000.



A three-axis diagram is utilized because the three technology groups have distinct levels of greenhouse gas emissions. Coal technologies emit greenhouse gases at roughly twice the rate of natural gas technologies. Nuclear and renewable technologies have no direct emissions, but are responsible for small amounts of life-cycle greenhouse gas emissions. A small fraction of U.S. electricity (< 4%) is generated using petroleum products. This contribution is included on the coal axis, as the emission rate for oil-fired generation is most similar to that of coal.

An average emission factor is developed for each axis using EPA's Emissions & Generation Resource Integrated Database (E-GRID) in conjunction with life-cycle emission considerations developed in this dissertation and in other studies (Tables 1 - 6). The E-GRID database provides emissions, operating, and fuel resource data for every U.S. power plant.[91] E-GRID is used to provide an operating emission rate for coal, oil, and natural gas plants, which represents the average rate of all U.S. plants. The latest data available from the E-GRID database is for 1998.

The emission factor for the ternary model includes emissions from fuel combustion as well as life-cycle emissions. A representative life-cycle study is used for each technology to provide the basis for life-cycle emissions. Construction, operation, and decommissioning emissions are normalized in terms of Tonnes CO_2/GW_eh and treated as constants. Emissions from the fuel cycle are dependent on the amount of fuel consumed, which is controlled by plant efficiency. Emissions occurring during the fuel cycle are scaled in proportion to the ratio of operating emissions between the studied plant and the average U.S. plant. (The ratio of emission rates should correspond to the rate of fuel consumption and therefore should adjust the fuel-cycle emission contribution accordingly. See Note* on Tables 2 & 3.

Table 1: U.S. Average Emission Rates Used For Ternary Diagram (Tonnes CO_2-equiv./GW_eh)

Ternary Diagram Axis	Average U.S. Life-Cycle Emission Rate (Tonnes CO_2-equiv./GW_eh)	Notes
Natural Gas	622	See Table 2
Coal/Oil	1,030	See Tables 3-5
Nuclear/Renewable	18	See Table 6

Table 2: U.S. Natural Gas Generated Electricity - Average Life-Cycle Emission Rate (Tonnes CO_2-equiv./GW_eh)

Process	1998 Average U.S. Plant Emission Rate[91]	Life-Cycle Study (This Work)	Average U.S. Life-Cycle Emission Rate
Fuel Combustion	509	383.1	509
Fuel-Cycle		83.7	111*
Materials & Construction		1.9	1.9
Decommissioning		0.02	0.02
Total (Tonnes CO_2-equiv. / GW_eh)			**622**

* Average Fuel Cycle Emission = (83.7 * 509 / 383.1) = 111 Tonne/GW_eh

Table 3: U.S. Coal Generated Electricity - Average Life-Cycle Emission Rate (Tonnes CO_2-equiv./GW_eh)

Process	1998 Average U.S. Plant Emission Rate[91]	Life-Cycle Study[37]	Average U.S. Life-cycle Emission Rate
Fuel Combustion	1,021	956.0	1,021
Fuel-Cycle		17.4	18.6*
Materials & Construction		1.1	1.1
Decommissioning		0.10	0.10
Total (Tonnes CO_2-equiv. / GW_eh)			**1,041**

* Average Fuel Cycle Emission = (17.4 * 1021 / 956.0) = 18.6 Tonne/GW_eh

Table 4: U.S. Oil Generated Electricity - Average Life-Cycle Emission Rate (Tonnes CO_2-equiv./GW_eh)

Process	1998 Average U.S. Plant Emission Rate[91]	Life-Cycle Study[92]	Average U.S. Life-cycle Emission Rate
Fuel Combustion	831	704.0	831
Fuel-Cycle		36.0	42.5*
Materials & Construction		1.5	1.5
Decommissioning		0.50	0.50
Total (Tonnes CO_2-equiv. / GW_eh)			**875**

* Average Fuel Cycle Emission = (36 * 831 / 704.0) = 42.5 Tonne/GW_eh

Table 5: Coal/Oil Emission Rate For Ternary Diagram (Tonnes CO_2-equiv./GW_eh)

Technology	Electricity Generation (% of 1998 U.S. Total)[91]	Average U.S. Life-cycle Emission Rate
Coal (See Table 2)	51.9%	1,041
Oil (See Table 3)	3.5%	875
Total	55.4%	--
Coal/Oil Weighted Average (Tonnes CO_2-equiv./GW_eh)		**1,030**

Table 6: Nuclear/Renewable Emission Rate For Ternary Diagram (Tonnes CO_2-equiv./GW_eh)

Technology	Electricity Generation (% of 1998 U.S. Total)[91]	Emission Rate
Nuclear[37]	18.6%	17
Hydro[93]	8.8%	18
Biomass[94]	1.4%	46
Wind[37]	0.08%	14
Solar PV (This work)	0.02%	39
Geothermal[92]	0.41%	15
Total	29.33%	--
Nuclear/Renewable Weighted Average (Tonnes CO_2-equiv./GW_eh)		**18.4**

Figure 9 shows the U.S. average emission factor (See Table 6) on each axis. Using these emission factors, an emission rate for any point on the ternary diagram (e.g., any mixture of technologies) can be calculated using the following equation:

$$\mathbf{GGER = (f_cE_c + f_gE_g + f_{nr}E_{nr})} \qquad \textbf{Eq. 4}$$

where:

GGER = greenhouse gas emission rate (tonnes CO_2-equiv. / GW_eh)

f_x = fraction of generation fueled by source x

E_x = emission rate for source x in (Tonnes CO_2 / GW_eh)

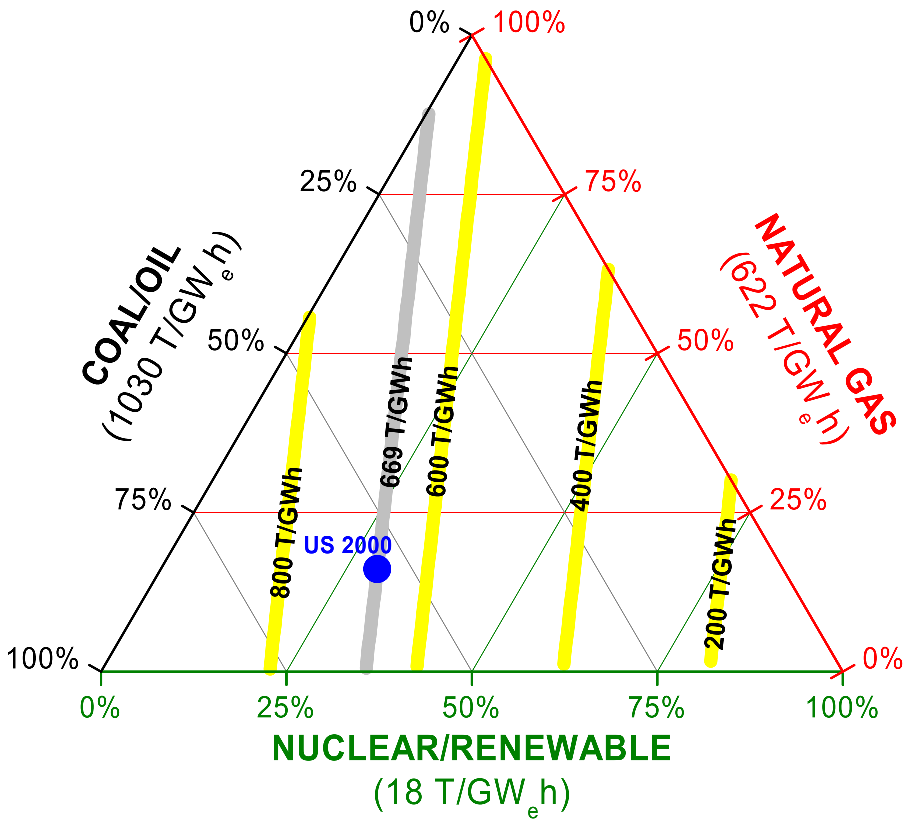
x = c: coal/oil, g: natural gas, nr: nuclear/renewable

A line of points with identical emission rates can be plotted on the ternary diagram. Because $f_{nr} + f_g + f_c = 1$, the equation for this line can be rewritten in terms of f_g as a function of f_c, by substituting $1-f_g-f_c$ for f_{nr} (Equation 4). In doing so, the constant emission rate line is expressed in the familiar y = mx + b format, where f_c is the independent variable, f_g is the dependent variable, and the remaining terms are held constant.

$$f_g = [(E_g-E_n)/(E_c-E_g)]\ f_c + (GGER - E_n)/[(E_g-E_n)] \qquad \textbf{Eq. 5}$$

Lines representing constant emission rates for electricity generation are plotted on Figure 9. As expected, the emission rates decrease in the direction of the lower right corner, representing increasing levels nuclear and renewable generation. Figure 9 also shows the U.S. electric fuel mix for year 2000, and the locus of points that would produce the same emission rate (669 Tonnes CO_2/GW_eh).

Figure 9: Life-cycle greenhouse gas emissions for U.S. electricity generation in 2000 are estimated at 669 tonnes CO_2-equivalent per GW_eh.



For the consideration of a capped greenhouse gas emission limit, the use of absolute emissions is more effective than emission rates. The constant emission rate lines in Figure 9 can be modified to show total emissions by incorporating total electric generation into Equation 4, as shown in Equation 6. A single line (emission target line) represents a set of supply distributions (i.e., % from coal, % from gas, % from nuclear/renewable) that meet both the projected electricity demand and the desired emission target. This line represents a continuum of alternatives that are possible for meeting the emission target. The equation for the emission target line is as follows:

$$(f_c E_c + f_g E_g + f_{nr} E_{nr}) * T_y = GGE \qquad \textbf{Eq. 6}$$

where:

f_x = fraction of generation fueled by source x

E_x = emission rate for source x in (Tonnes CO_2-equiv. / $GW_e h$)

T_y = total electricity generation in year y ($GW_e h$/year)

GGE = greenhouse gas emission target (Tonnes CO_2-equiv. / year)

x = c: coal/oil, g: natural gas, nr: nuclear/renewable

Because $f_{nr} + f_g + f_c = 1$, Equation 6 can be rewritten in terms of f_g as a function of f_c, with all remaining terms held constant:

$$f_g = [(E_n - E_c)/(E_g - E_n)]\ f_c + (GGE - E_n T_y)/[T_y (E_g - E_n)] \qquad \textbf{Eq. 7}$$

An emission level for the UNFCC proposed Kyoto protocol limit for the U.S. (1990 minus 7%) can be estimated by multiplying the U.S. fuel use in 1990 by the average emission rates for each technology group and multiplying by 0.93 to account for the7% reduction (Equation 8).

$$(\mathbf{f_cE_c + f_gE_g + f_{nr}E_n) * T_y * 0.93 = GGE_{Kyoto}} \qquad \textbf{Eq. 8}$$

where:

f_c = 1990 U.S. fraction of generation fueled by coal and oil = 0.55

f_g = 1990 U.S. fraction of generation fueled natural gas = 0.16

f_{nr} = 1990 U.S. fraction of generation powered by nuclear/renewable = 0.29

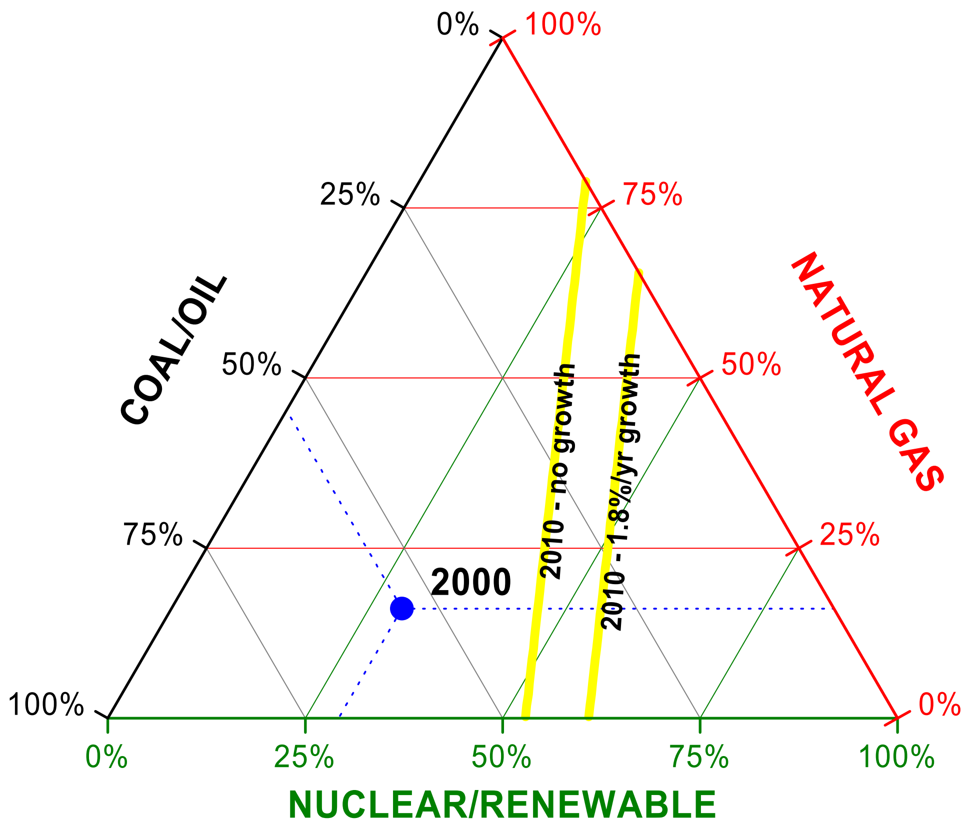
E_c = average U.S. emission rate for coal and oil = 1030 Tonnes CO_2/GW_eh
E_g = average U.S. emission rate for natural gas = 622 Tonnes CO_2/GW_eh
E_{nr} = average U.S. emission rate for nuclear/renewable = 18 Tonnes CO_2/GW_eh
T_y = total electricity generation in 1990 = 3.02×10^6 GW_eh

GGE_{Kyoto} = Kyoto-based U.S. electric industry emission rate = 1,877 x 10^6 Tonnes CO_2-equiv. per year

The Kyoto-based U.S. required emission rate U.S. electric industry emission rate (1,877 x 10^6 Tonnes CO_2-equiv per year) assumes that the U.S. electric industry provides emission reduction proportional to their contribution of total U.S. emissions. Total compliance would require proportional contributions from other sectors (e.g., transportation, manufacturing) as well. Figure 10 uses this Kyoto emission target and plots emission target lines for two possible future scenarios, a) no growth in U.S. electricity consumption from 2000 levels, and b) electricity consumption growing at 1.8% per year between 2000 and 2010.

Points on the emission target line represent fuel mixtures which meet the emission target, while points to the right are fuel mixtures with emissions below the target. Meeting this emission target requires a drastic shift in generating technologies. Numerous construction options could be used to make the shift from the current mix of generating technologies to one that reaches the emission target line. These options represent alternatives that may be promoted or prevented by U.S. policy initiatives. Section 6.4 will use the ternary methodology developed here to evaluate the viability of meeting emission objectives using basic fuel-switching alternatives.

Figure 10: Significant fuel-switching is required for Kyoto-based emission target compliance.



5. Results

This section summarizes the data from the net energy analysis (NEA) of two electricity generating systems, a combined-cycle natural gas power plant and a building-integrated thin film photovoltaic system. This section includes a summary of energy data and greenhouse gas emissions associated with these two systems. Section 6 compiles the data into metrics for comparison of technologies and provides policy applications and discussion.

For ease of reading, the tables in this section will provide a summary of data and results. Detailed tables along with references, notes, and calculations are contained in Appendices A and B as indicated. Additional analysis of results, including ternary analysis, is included in Section 6.

5.1. Combined -Cycle Natural Gas Power System

The natural gas power plant used as the basis for this study is a 2 x 1 combined-cycle natural gas power plant. The plant was constructed by Aquila Energy and is located in Cass County, Missouri.[95] The system consists of two Siemens Westinghouse 501FD combustion turbines and a nominal 250 MW steam turbine. Both combustion turbines are coupled with heat recovery steam generators which offer an inexpensive means for adding peaking capacity.

The 2 x 1 combined-cycle refers to the use of two combustion turbines and one steam turbine to generate electricity. Compressors convey inlet air into the combustion turbines where natural gas is mixed with the air and burned in the combustion section. The products of combustion expand

and drive the combustion turbine, which in turn rotates the generator shaft to produce electricity. High-pressure steam is used to recover residual heat from the combustion turbine generators and is then used to turn the steam turbine producing additional electricity. The exhaust of the steam turbine is directed to a water-cooled condenser.[95]

In addition to the combustion and steam turbines, plant facilities include a general services building, electrical equipment building, and water treatment building.[95] The general services building houses a control room, control equipment room, offices, shop, and warehouse. The electrical equipment building houses heat exchangers, electrical switchgear, station batteries, service pumps, and laboratory. The water treatment building contains water treatment equipment, chemical feed equipment, firewater pumps, and treatment equipment controls.

5.1.A. Natural Gas Plant Net Energy Analysis

The life cycle for the natural gas plant consists of natural gas production and transmission, fabrication of equipment and structural materials, plant construction, operation, decommissioning, and land reclamation (Figure 11). The NEA is performed by estimating the energy requirements for each phase of the life cycle and comparing these “energy inputs” to the useful electrical output of the plant (Table 7).[84]

Figure 11: Natural Gas Plant Life-Cycle and Energy Payback Ratio

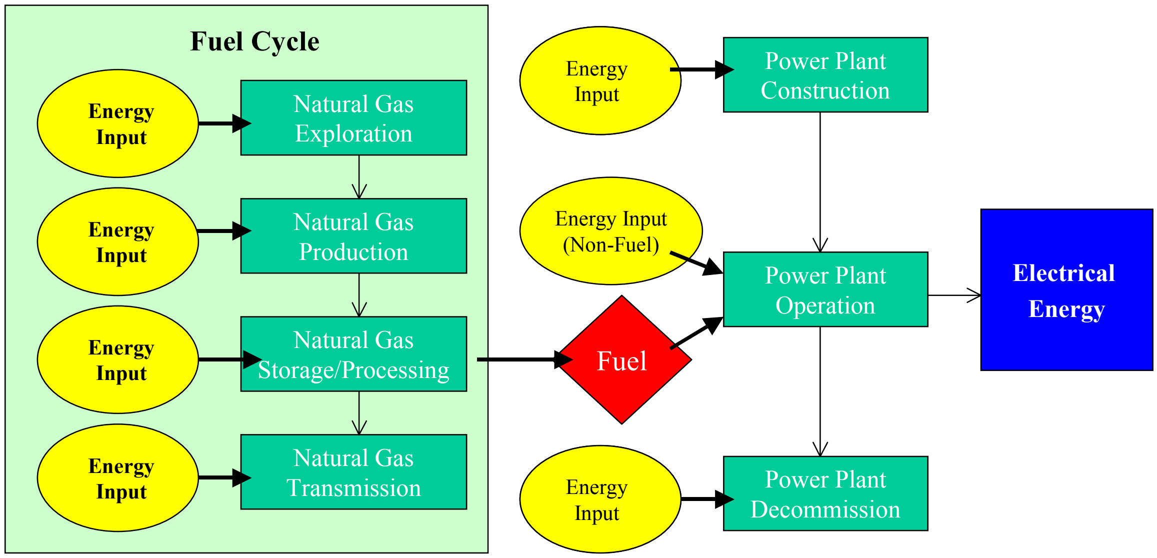


Table 7: Summary Net Energy Analysis for 620 MW Natural Gas Plant (Terajoules per 30 full power years)*

Process	Energy Input (TJ)
Direct Fuel Energy Input	**1,223,000**
Life-cycle Energy Inputs	
Fuel Cycle	135,800
Plant Construction & Materials	1,678
Plant Operation & Maintenance	6,004
Plant Decommission & Land Reclamation	59
Life-cycle Energy Input	**143,500**
Electrical Energy Output	**587,000**

*Details included in Appendix A.

5.1.A.1. Electrical Energy Output

The power output from a combined-cycle plant is highly temperature dependent. The Aquila plant is designed to generate 587 MW at incoming ambient air conditions of 99^{o}F, but is expected to be capable of providing 658 MW at -17°C.[95] This study estimates an average power output of 620 MW. It is assumed for this study that the plant will operate at 75% capacity annually over a 40-year lifetime. Therefore, the total life-cycle output is 587,000 TJ_e.

5.1.A.2. Direct Fuel Input

As with power output, thermal efficiency also varies with temperature and operating conditions. This study estimates an average net thermal efficiency of 48%. Based on this efficiency, 1,222,000 TJ_{th} of direct fuel is supplied to the plant turbines in the form of natural gas. Table 8 provides a summary of plant operating characteristics and energy requirements.

Table 8: 620 MW Natural Gas Plant Operating Characteristics[95]*

Gross Power Output	632.4	MW
System Auxiliaries	12.4	MW
Net Power Output	620.0	MW
Calendar Year Lifetime	40	years
Capacity Factor	75%	
Full Power Lifetime	30	years
Lifetime Output (Net)	587,000	TJ_e
Thermal Efficiency (Net)	48%	
Direct Fuel Input	1,223,000	TJ_{th}

*Details Included in Appendix Table A2.

5.1.A.3. Natural Gas Plant Fuel Cycle

The natural gas fuel cycle includes exploration, production, storage, processing, and transmission. Table 9 provides a summary of fuel cycle energy inputs. The fuel cycle is the most significant portion of the natural gas plant life cycle when evaluating the energy inputs. For every 10 m^3 of natural gas delivered to end users (e.g., delivered to the reference plant), approximately 1 m^3 is consumed during production, processing, and transmission.[96]

Table 9: Fuel Cycle Energy Requirements for a 620 MW Natural Gas Plant (Terajoules per 30 full power year lifetime)*

Process	**Life-Cycle Energy Input (TJ)**
Natural Gas Exploration	9,285
Natural Gas Production, Storage & Processing	90,201
Natural Gas Transmission	36,304
Fuel Cycle Total	**135,800**

*Details included in Appendix A.

Natural gas exploration involves geologic analysis, drilling, and well installation. Energy consumed during exploration was estimated using the I/O method, using data on the cost of adding proven natural gas reserves,[97] and an I/O energy intensity for natural gas exploration.

During field production, wells are used to draw natural gas from underground formations. Production energy inputs were estimated primarily using the PCA method. Significant energy losses occur during venting (natural gas released into the air), flaring (burning off natural gas), and other well field operations fueled by natural gas.[96] In addition to combustion and leaks, the PCA method was used to estimate the embodied energy and emissions associated with the manufacturing of production pipe. The I/O method was used to account for pipe installation, engineering, and administration.

Natural gas processing refers to preparing natural gas so that it meets pipeline specifications.[98] Natural gas itself is used to power the processing operation, which includes the removal of water, acid gas (hydrogen sulfide and CO_2), nitrogen, and heavier hydrocarbons. The removal of heavier hydrocarbons from the natural gas is called extraction, and is frequently required to meet pipeline specifications.[99] However, because this process is sometimes profitable, it is assumed to have either a breakeven or positive energy balance. Therefore, the extraction energy requirements for heavy hydrocarbons are excluded from the natural gas plant life-cycle. Processing inputs include the energy used for water, acid gas, and nitrogen removal.[100] As with production, fuel combustion and fugitive losses (natural gas releases or leaks) account for the vast majority of energy input from processing.

The U.S. has an extensive natural gas transmission pipeline network consisting of approximately 300,000 miles of pipe.[83] Compressor stations recompress and convey the natural gas at typical intervals of every 100-200 miles. These stations are fueled by natural gas and are the primary consumers of energy in the transmission process. The PCA method was used to account for transmission fuel losses and the energy embodied within pipeline materials. The I/O method was utilized to account for the energy expenditures of compressor station materials, engineering, installation, and operating and maintenance labor.

Several of the energy estimates described above were performed for a large U.S. natural gas infrastructure. The life-cycle energy embodied in the materials and operation of this system must be applied across all end-users of the natural gas. Therefore, only a fraction of the total energy consumed during each phase of the fuel cycle is applied to the natural gas plant. This fraction is calculated as the annual natural gas plant consumption divided by the average annual U.S. production (See Appendix A). Currently, large gas plants utilized at a high capacity factor are rare in the U.S., therefore, the natural gas plant used for this study would consume a significant portion of the total U.S. production (0.2%).

5.1.A.4. Natural Gas Plant Material and Construction

An inventory of plant structural materials was compiled including quantities of pipe, structural steel, and concrete.[101] Quantities of alloying metals in steel (e.g., manganese, chromium) were calculated based on ASTM specifications. The PCA method was used to calculate the energy requirements for each material based on embodied energy factors. As shown in Table 10, concrete required the greatest energy input, followed by high alloy steel. Energy embodied in plant equipment (e.g., turbines, compressors) was calculated using the I/O method based on equipment cost. Based on the I/O analysis, combustion turbines account for approximately two-thirds of the plant equipment energy. The energy requirements for plant construction were estimated by the I/O method using cost data provided by Aquila Energy.[95]

Table 10: Material Energy Requirements for 620 MW Natural Gas Plant*

Element or Alloy	Mass[101] Tonnes	Embodied Energy GJ/Tonne	Energy Totals GJ
Aluminum	1.8	201.4	355
Chromium	0.32	82.9	27
Concrete	29,660	1.4	40,876
Copper	4	130.6	479
Iron	73	23.5	1,718
Carbon Steel	135	34.4	4,632
High Alloyed Steels	1,386	53.1	73,594
Manganese	17	51.5	864
Molybdenum (FeMo)	0.17	378.0	65
Plastic	15	54.0	820
Silicon	3.8	158.6	608
Vanadium (FeV)	0.51	3,711.2	1,885
Total	**31,300**		**126,000**

*Details and references for embodied energy factors included in Appendix A.

5.1.A.5. Natural Gas Plant Operation and Maintenance

The energy requirements for plant operation and maintenance were estimated by the I/O method using cost data and maintenance schedules provided by Aquila Energy.[95] Natural gas consumed at the turbines, including that used to generate auxiliary power, is included as a "direct fuel" input and is therefore excluded from operating and maintenance life-cycle requirements. Table 11 provides a summary of the items and energy inputs associated with plant operation and maintenance (O&M).

Table 11: Operation Energy Requirements for 620 MW Natural Gas Plant*

Item	**Life-cycle Energy Input (TJ)**
Water Supply & Treatment	625.6
Staff Labor	520.0
Major Maintenance	1,710.2
Routine Maintenance	185.7
Materials & Supplies	247.1
Contract Services	20.3
Administrative Overhead	130.3
Other Expenses	13.7
Startup Costs	176.5
Maintenance Subtotal	***3,629***
Replacement Parts	1,713.7
Repair Parts	661.2
Parts Subtotal	***2,375***
Total	**6,004**

*Details included in Appendix A.

5.1.A.6. Natural gas Plant Decommissioning and Land Reclamation

The energy required to decommission the plant was estimated using the I/O method. The cost for decommissioning was estimated as a combination of equipment dismantling and building demolition.[95,102] Land reclamation refers to returning the land to its natural state. For the natural gas plant life cycle, this includes the plant site, and also a representative fraction of the land used for natural gas production and transmission. Energy requirements were estimated using the I/O method based on the cost for seeding and fertilizing multiplied by a forestry I/O energy intensity.

5.1.B. Natural Gas Plant Life-cycle Greenhouse Gas Emissions

The energy inputs compiled in the net energy analysis provide the basis for calculating greenhouse gas emissions. Greenhouse gas emissions were estimated in four ways:

- Multiplying energy use by a fuel-specific emission factors (PCA method);
- Multiplying material mass by a material embodied emission factor (PCA method);
- Estimated methane leaks throughout the system (PCA method);
- Multiplying cost-based energy estimates by a CO_2 intensity factor (I/0 method).

The total life-cycle emissions for the natural gas system are 76.4 million metric tonnes of CO_2-equivalent. Table 12 shows the contribution from each process, described further in the following sections.

Table 12: Life-Cycle Emissions for a 620 MW Natural Gas Plant (Tonnes CO_2-Equivalent per 30 full power year lifetime)*

Process	**Tonnes CO_2-Equivalent**
Direct Fuel Plant Combustion Emissions	**62,220,000**
Indirect Life-cycle Emissions	
Fuel Cycle	13,650,000
Plant Construction & Materials	131,100
Plant Operation & Maintenance	423,100
Plant Decommission & Land Reclamation	3,960
Indirect Life-cycle Emissions	**14,210,000**
Total Emissions	**76,430,000**

*Details included in Appendix A.

5.1.B.1. Emissions from Direct Fuel Consumption

Direct fuel combustion during plant operation contributes the majority of greenhouse gas emissions, accounting for 81% of the total. Combustion emissions for natural gas are estimated with EPA emission factors. The vast majority of combustion emissions are in the form of carbon dioxide, with only trace amounts of methane and nitrous oxide emissions (Table 13).

Table 13: Emission Factors for Natural Gas Power Generation

Greenhouse Gas	Tonne per MJ Natural Gas Input[103]	100-year Global Warming Potential[14]	Tonne CO_2-equiv. per MJ natural gas input
Carbon Dioxide	50.6	1	50.6
Methane	0.00097	21	0.020
Nitrous Oxide	0.00093	310	0.287

5.1.B.2. Natural Gas Plant Fuel-Cycle Emissions

The fuel cycle contributes significantly to the natural gas life cycle, comprising 18% of the total emission rate. Table 14 shows the contribution from each fuel-cycle process.

Table 14: Fuel-Cycle Emissions for a 620 MW Natural Gas Plant (Tonnes CO_2-Equivalent per 30 full power year lifetime)*

Process	Tonnes CO_2-Equivalent
Exploration	655,700
Production, Storage & Processing	8,217,000
Transmission	4,777,000
Total Fuel Cycle	**13,650,000**

*Details included in Appendix A.

Energy losses from the natural gas fuel-cycle are described in Section 5.1.A.3. The vast majority of corresponding greenhouse gas emissions occur both as the byproducts of natural gas combustion (primarily CO_2), and as fugitive methane releases. During production, natural gas consisting primarily of methane may be released directly or burned at the base-site. Processing and transmission operations burn natural gas for fuel (releasing CO_2) and release methane as fugitive losses from compressor stations, metering and regulating stations, and pneumatic devices.[104]

The fraction of losses estimated as methane releases (as opposed to natural gas combustion) has a significant impact on life-cycle emissions, due to the global warming potential (21) of methane. This study employed U.S.EPA estimates of methane emissions,[83] which correspond to a methane release rate of 1.4% of production. Based on this methane release rate, just over half of the fuel-cycle emissions are the result of methane releases. However, estimates of methane leakage from the natural gas fuel cycle vary greatly, ranging from 1% - 11% of production,[116] with most commonly cited estimates ranging from 1% - 4%.[104] The sensitivity of the emission estimates to the assumed rate of methane releases is addressed in Section 6.2.A.

5.1.B.3. Plant Materials and Construction, O&M, and Decommissioning

After accounting for direct fuel and the fuel cycle, the remaining life-cycle components contribute slightly less than 1% of total emissions. Individual contributions are shown in Table 15.

Table 15: Emissions From Remainder of 620MW Natural Gas Plant Life-Cycle (Tonnes CO_2-Equivalent per 30 full power year lifetime)

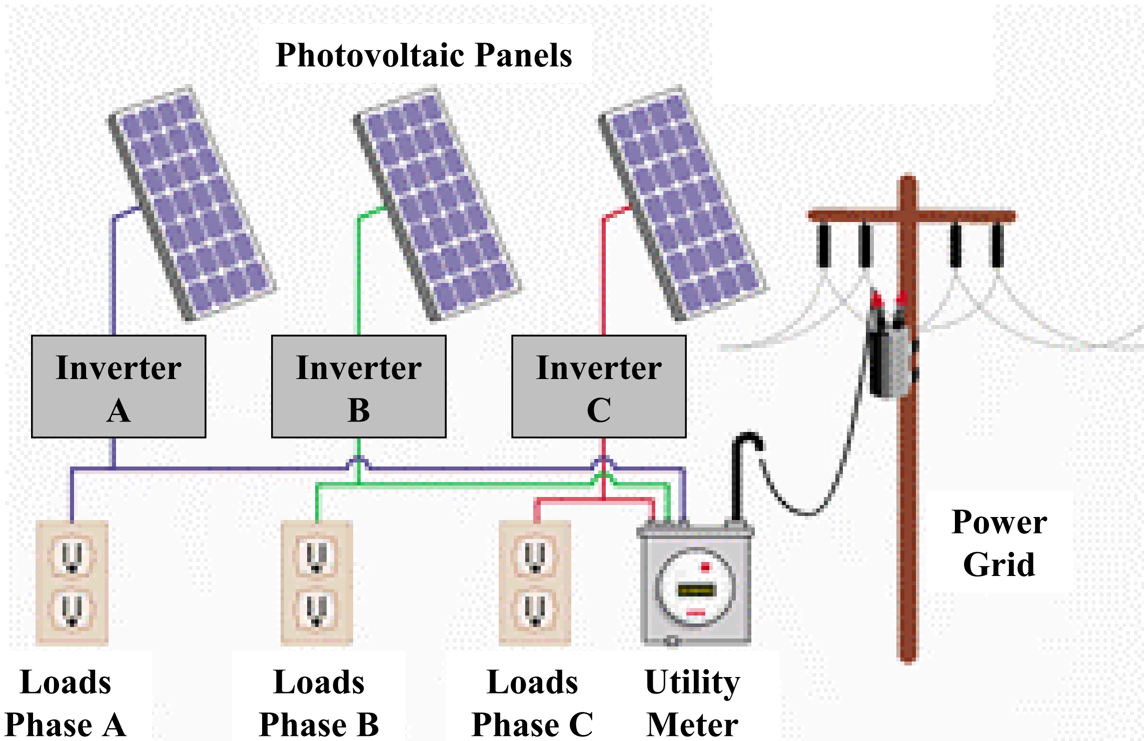
Life-cycle Component	Tonnes CO_2-Equivalent
Materials and Construction	131,100
Operation & Maintenance*	423,100
Decommission & Land Reclamation	3,960
Total	**558,100**

*Excludes direct fuel; includes replacement parts. Details included in Appendix A.

5.2. Building-Integrated Photovoltaic Power System

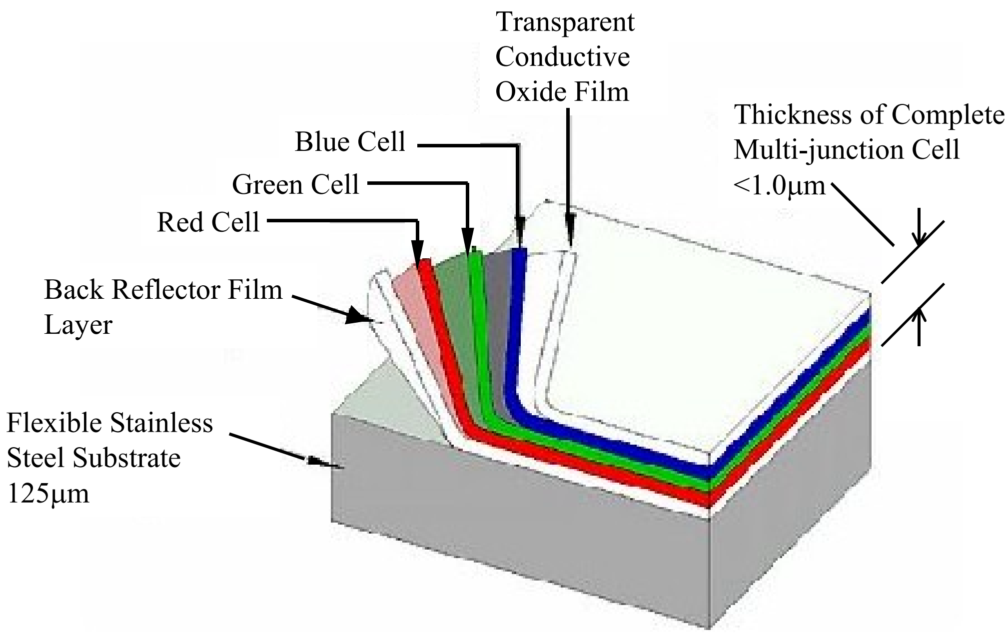
The BigHorn Center, located in Silverthorne, Colorado, is site to a building-integrated photovoltaic (PV) system utilizing thin-film amorphous silicon technology.[105] Approximately 160 m^2 of Uni-Solar® structural solar roofing modules are laminated onto the building's south-facing roof panels. The modules generate up to 8 kW of direct current (DC) electricity, collected at one of three combiner boxes.[106] Each combiner box connects to an inverter, which converts the DC current to alternating current (AC) tied directly to the building's three-phase electrical system (Figure 12).[107] The system is also grid-tied, and excess electricity may be sold to the local utility under a net-metering agreement.[108]

Figure 12: A grid-tied PV system can return excess power to the grid. (Source: NREL108)



The Uni-Solar® PV modules consist of a thin sheet of stainless steel substrate onto which various thin film layers are sequentially deposited.[109] Three separate amorphous silicon (a-Si) layers (Figure 13) are used to convert visible and near-infrared solar radiation to electricity. Each layer responds optimally to a different spectral distribution, improving overall conversion efficiency. A transparent conductive oxide film transmits the mobilized electrons to the module terminal. Solar energy that passes through the a-Si layers without absorption is reflected back through the cells by the back reflector layer. A polymer matrix encapsulates the module and inhibits environmental deterioration.

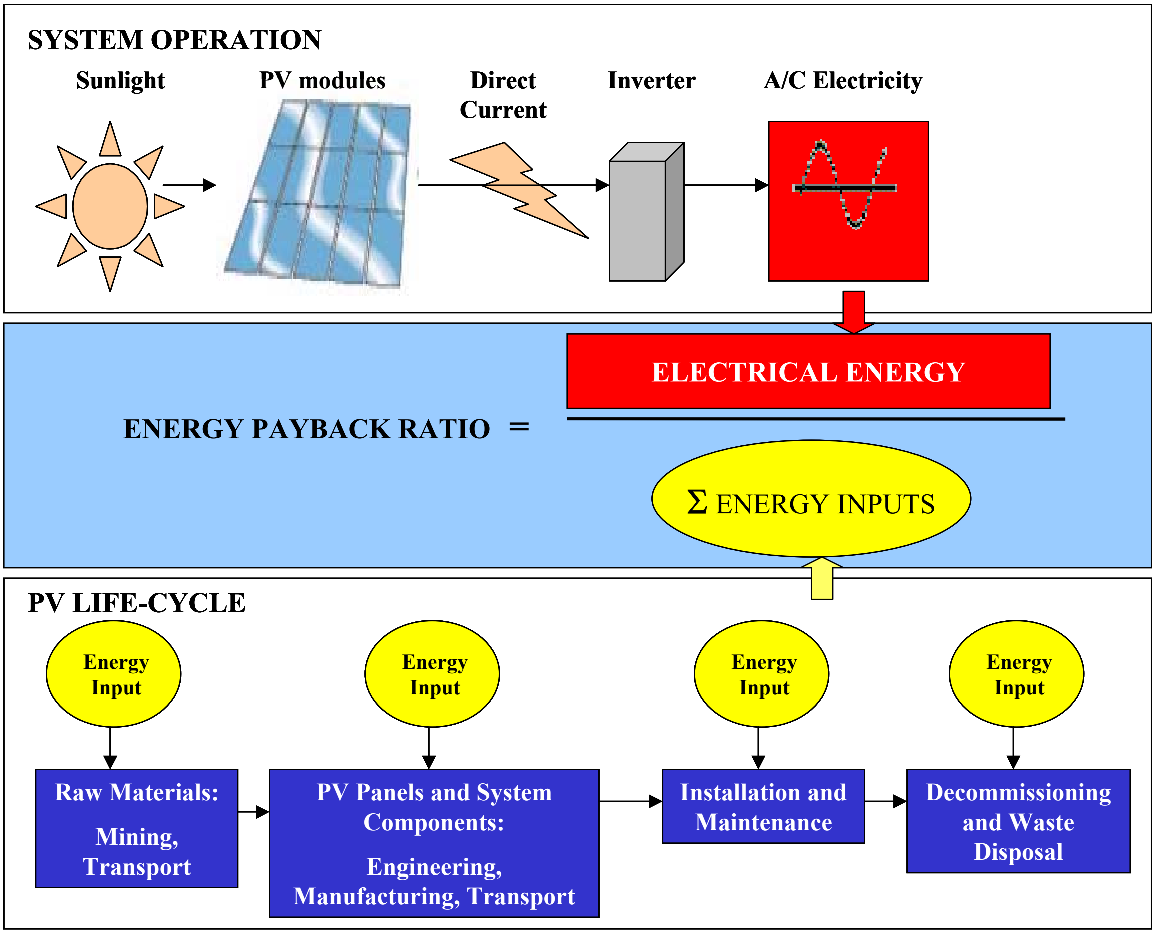
Figure 13: Uni-Solar® amorphous silicon PV cells convert visible and near-infrared solar radiation to electricity [109]



5.2.A. Photovoltaic Net Energy Analysis

The PV life cycle, shown in Figure 14, includes mining and transporting raw materials, manufacturing and transportation of PV panels and other system components, transportation of the finished product, installation and maintenance, and system decommissioning. The NEA compares the energy inputs from each of these phases to the useful electrical output (Table 16).[84]

Figure 14: The Energy Payback Ratio compares the useful electrical output to the life-cycle energy inputs.



5.2.A.1. Energy Output

The output of the PV life cycle is defined as the total AC electricity generated over the lifetime of the system and may be estimated using actual performance data, or by using the average solar insolation rate and the module conversion efficiency. The output for a PV system is largely controlled by the efficiency at which modules convert sunlight to electricity. The Uni-Solar® PV modules are factory-rated to convert solar radiation to DC electricity at 5.7% efficiency, allowing the array to generate 8kW of DC power during peak insolation.[109]

Table 16: Summary of Net Energy Analysis for 8 kW Thin Film PV System (GJ per 30 calendar year lifetime)*

Process	**Energy Input (GJ)**
Renewable Energy Input (Incident Solar Radiation)	**27,680**
Life-cycle Energy Inputs	
Fuel Cycle	0
System Construction & Materials	189.4
System Operation & Maintenance	11.0
System Decommission	4.3
Life-cycle Energy Input	**205**
Energy Output	**1,165**

*Details included in Appendix B.

System losses have a significant impact on the available energy provided over the system lifetime. Approximately 10% of the potential solar energy is unavailable because the BigHorn PV system modules have slightly less than optimal orientation (See Appendix B). Losses at the inverters (converting DC to AC) and throughout the system (line losses) reduce the available AC power by approximately 20%.[106] Environmental deterioration will reduce module performance by an estimated 15% by the end of its useful life (30 years).[110] The cumulative impact of module degradation reduces the average annual output by 8%. After consideration of system losses, the estimated lifetime energy output is 1,165 GJ (Table 17).

Table 17: Electrical Output for 8 kW Thin Film PV System (GJ per 30 calendar year lifetime)*

Potential Generation with Optimal Slope & Orientation	1,727 GJ
Designer Estimated Direct Current Module Generation[106]	1,578 GJ
Degradation Losses[110]	-120 GJ
DC to AC conversion losses[106]	-219 GJ
Other system losses[106]	-74 GJ
Lifetime Estimated Available AC Generation	**1,165 GJ**

*Details included in Appendix B.

The performance of any new PV system is somewhat uncertain. Preliminary data during March 2001 showed the system to under-perform design expectations by about 25%. This is not uncommon for PV systems during the first months of operation, and system performance is expected to meet design expectations following a short period of system optimization.[106] Therefore, the expected output (1,165 GJ) is considered to provide the best estimate of long-term performance for this study.

5.2.A.2. PV System Energy Inputs

PV systems generate electricity directly from sunlight, therefore there are no fuel-related energy requirements. A total of 205 GJ of energy is consumed throughout the life cycle of the PV system (Table 18). The energy requirements are divided into three categories: materials and construction, operation and maintenance, and decommissioning. The energy requirements for each category are described in the following sections.

Table 18: Life-Cycle Energy Requirements for 8 kW Thin Film PV System (GJ for 30 calendar year lifetime)*

Component	Energy Input* (GJ)	% of Total
Materials and Construction	189.4	92.5%
Operation & Maintenance	11.0	5.4%
Decommissioning	4.3	2.1%
Total PV Life-Cycle Energy Input	**205**	**100%**

*Operation & Maintenance includes replacement parts. Details included in Appendix B.

5.2.A.3. PV System Materials and Construction

The PV system consists of 123 individual modules laminated onto standard galvanized aluminum standing seam roofing panels, providing approximately 160 m^2 of surface area. The remainder of the PV system components (excluding the modules themselves), are collectively referred to as the Balance-of-System (BOS). Table 19 lists the energy requirements for the PV system materials and construction (installation).

Table 19: Construction and Material Energy Inputs for 8 kW Thin Film PV System (GJ for 30 calendar year lifetime)*

Process	**Energy Input (GJ)**	**% of Total**	**NEA Method**
Materials and Manufacturing	123.0	65.0%	PCA
Engineering and Administration	39.3	20.8%	PCA
Inverters*	4.0	2.1%	PCA
Wiring	2.9	1.5%	PCA
Installation	12.9	6.8%	I/O
Transportation	7.2	3.8%	PCA
Total Construction and Material Energy	**189**	**100%**	

*Details are included in Appendix B.

The energy inputs associated with the PV modules (Table 19) include acquisition and processing of primary materials, intermediate transportation, module manufacturing, engineering and administration and final transportation. Detailed calculations and references are included in Appendix B. The energy required to manufacture and install the aluminum roofing panel is intentionally excluded, assuming the building would require a similar roof regardless of the addition of the PV system. However, the energy required to transport the roofing panel and module from San Diego is included (1000 miles), assuming that alternative roofing material could otherwise be obtained from Denver (70 miles).

The BOS consists of combiner boxes, invertors, circuit breakers, lightning arrestors, and several hundred feet of electrical wiring.[106] Modules are laminated directly onto roofing panels, therefore no array support is required. The majority of the BOS energy consumption occurs during inverter manufacturing. Lesser energy requirements are associated with system electrical wiring. The energy associated with remaining components is presumably small.

Installing the building-integrated PV system involves mounting the roofing panels, integrating the PV modules, and installing and connecting the BOS. A portion of the installation energy is excluded from the NEA, assuming builders would install a similar roof regardless of the addition of the PV system.

5.2.A.4. PV System Operation and Maintenance

The reliability of power conditioning equipment (inverter) is the primary consideration for determining O&M energy requirements.[111,112] This study assumes a 15 calendar year inverter lifetime (i.e., inverters are replaced once). Inverter energy requirements are estimated with the PCA method. System optimization and miscellaneous O&M are estimated by the I/O method.

5.2.A.5. Decommissioning and Disposal

Decommissioning and disposal is generally considered a negligible component of the energy input requirements and is frequently omitted from analysis. While future recycling programs are viable for some PV technologies,[113] it is likely that amorphous silicon modules would be disposed of at the end of their useful life. The PV modules researched in this study contain no toxic semi-conductor materials and are therefore suitable for sanitary landfill disposal. Energy requirements and emissions are estimated using the I/O method for landfill disposal of the PV system components and for disposing of wastes associated with manufacturing.[113,62]

5.2.B. Photovoltaic Life-Cycle Greenhouse Gas Emissions

PV systems generate electricity using the photoelectric effect, which in itself has no associated emissions. However, due to reliance on an existing fossil fuel infrastructure, many phases of the life cycle have corresponding greenhouse gas emissions. The following methods were used to estimate emissions:

- Multiplying energy use by a fuel-specific emission factors (PCA method);
- Multiplying material mass by material embodied emission factors (PCA method);
- Multiplying cost-based energy estimates by a CO_2 intensity factor (I/O method).

The total emissions for the 8kW PV system life cycle are 12.5 metric tonnes of CO_2-equivalent over a 30 calendar year lifetime. Table 20 shows the contribution from each component. Details are included in Appendix B.

Table 20: Life-Cycle Greenhouse Gas Emissions for 8 kW Thin Film PV System (GJ for 30 calendar year lifetime)*

Life-Cycle Component	Tonnes CO_2-Equivalent
Construction & Materials	11.44
Operation & Maintenance	7.76
Decommissioning & Land Reclamation	2.97
Total Life-cycle Emissions	**12.5**

Construction and material estimates are based primarily on PCA methods and itemized in Table 21. A single replacement of system inverters is included with the operation and maintenance requirements in Table 21.

Table 21: Construction and Material Related Greenhouse Gas Emissions for an 8 kW Thin Film PV System (GJ for 30 calendar year lifetime)*

Process	Tonnes CO_2-equivalent	% of Total
Materials and Manufacturing	7.32	64.0%
Engineering and Administration	2.21	19.3%
Inverters*	0.29	2.5%
Wiring	0.18	1.6%
Installation	0.90	7.9%
Transportation	.53	4.6%
Total Construction and Material Emissions	**11.4**	**100%**

*Details included in Appendix B.

6. Discussion

6.1. Energy Metrics

6.1.A. Combined -Cycle Natural Gas Plant Energy Metrics

Figure 15 summarizes the NEA for the combined-cycle natural gas plant. Plant fuel represents the largest energy input by far. Contributions from the indirect components of the life cycle are significant, primarily due to the energy investment in the fuel cycle. Figure 16 illustrates the significance of using the life-cycle approach of energy analysis in place of conventional analysis at the plant only. While fuel efficiency is 48% at the plant, consideration of the entire life-cycle reduces the overall efficiency to 43%.

Figure 15: Summary of the Net Energy Analysis for 620 MW Natural Gas Plant (Terajoules per 30 full power year lifetime)

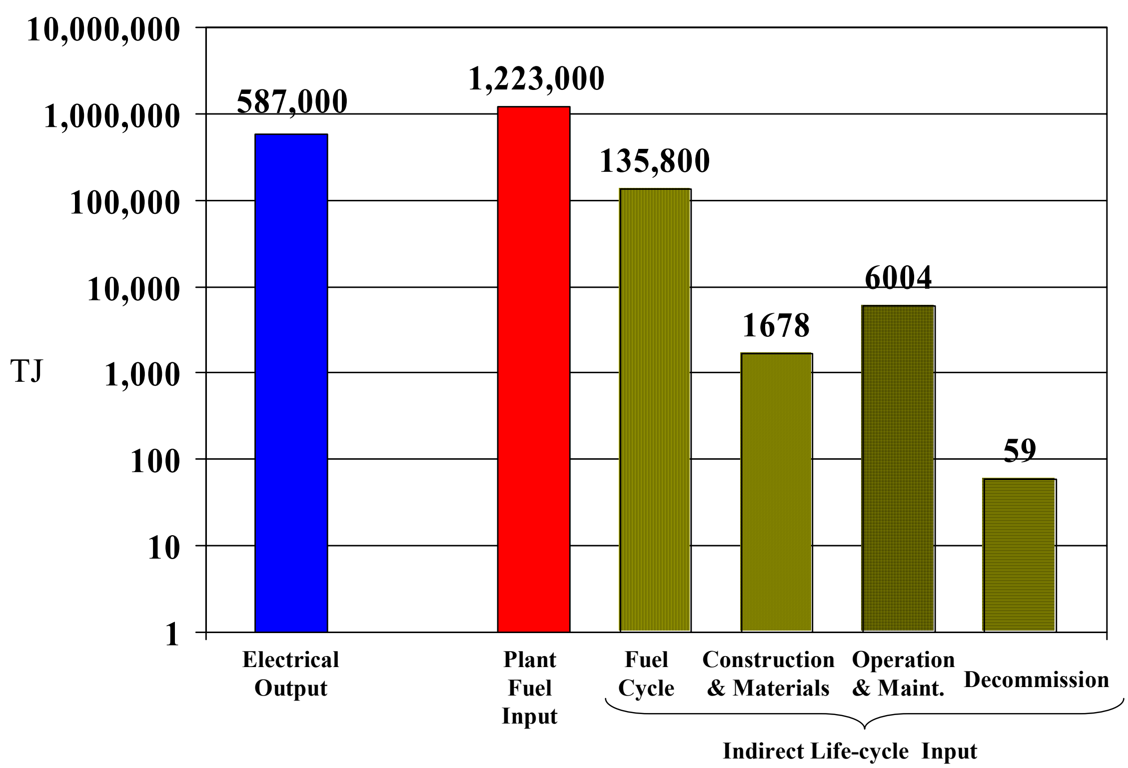


Figure 16: Conventional Plant Efficiency and Life-Cycle Efficiency for the Combined-Cycle Natural Gas Plant

Normalized Energy Inputs	Output
Direct Plant Fuel Input: 1,223,000 TJ_{th}	Net Electrical Output: 587,000 TJ_e
Indirect Life-cycle Input: 144,000 TJ_{th}	
Total: 1,366,000 TJ_{th}	

$$\textbf{PLANT FUEL EFFICIENCY} = \frac{587{,}000\ TJ_e}{1{,}223{,}000\ TJ_{th}} = \mathbf{48\%}$$

$$\textbf{LIFE-CYCLE ENERGY EFFICIENCY} = \frac{587{,}000\ TJ_e}{1{,}223{,}000\ TJ_{th} + 144{,}000\ TJ_{th}} = \mathbf{43\%}$$

The calculation for the Energy Payback Ratio is illustrated in Figure 17. The EPR considers only indirect energy inputs which are dominated by the fuel cycle. The remainder of the life cycle (plant construction, operation, decommissioning, and land reclamation) accounts for only about 5% of the indirect energy inputs.

Figure 17: Energy Payback Ratio For a 620 MW Combined -Cycle Natural Gas Plant Energy Payback Ratio

Indirect Life-cycle Energy Inputs		Life-cycle Output
Fuel Related:	136,000 TJ_{th}	Net Electrical Output: 587,000 TJ_e
Construction & Materials:	1,680 TJ_{th}	
Operation:	6,000 TJ_{th}	
Decommissioning:	59.0 TJ_{th}	
Total:	144,000 TJ_{th}	

$$\textbf{ENERGY PAYBACK RATIO} = \frac{587{,}000\ TJ_e}{144{,}000\ TJ_{th}} = \mathbf{4.1}$$

6.1.B. Photovoltaic Energy Metrics

Figure 18 summarizes the NEA for the building-integrated photovoltaic system. The conversion of incident radiation to electrical output (renewable energy input) is noticeably low. The vast majority of the indirect life-cycle inputs are associated with construction and materials. Figure 19 illustrates the significance of using a life-cycle approach of energy analysis in place of conventional analysis. While the factory rated output of the PV modules are 5.7%, consideration of the entire life-cycle reduces the overall efficiency to 4.2%.

Figure 18: Summary of the Net Energy Analysis Summary for an 8 kW Thin Film PV System (Gigajoules per 30 calendar year lifetime)

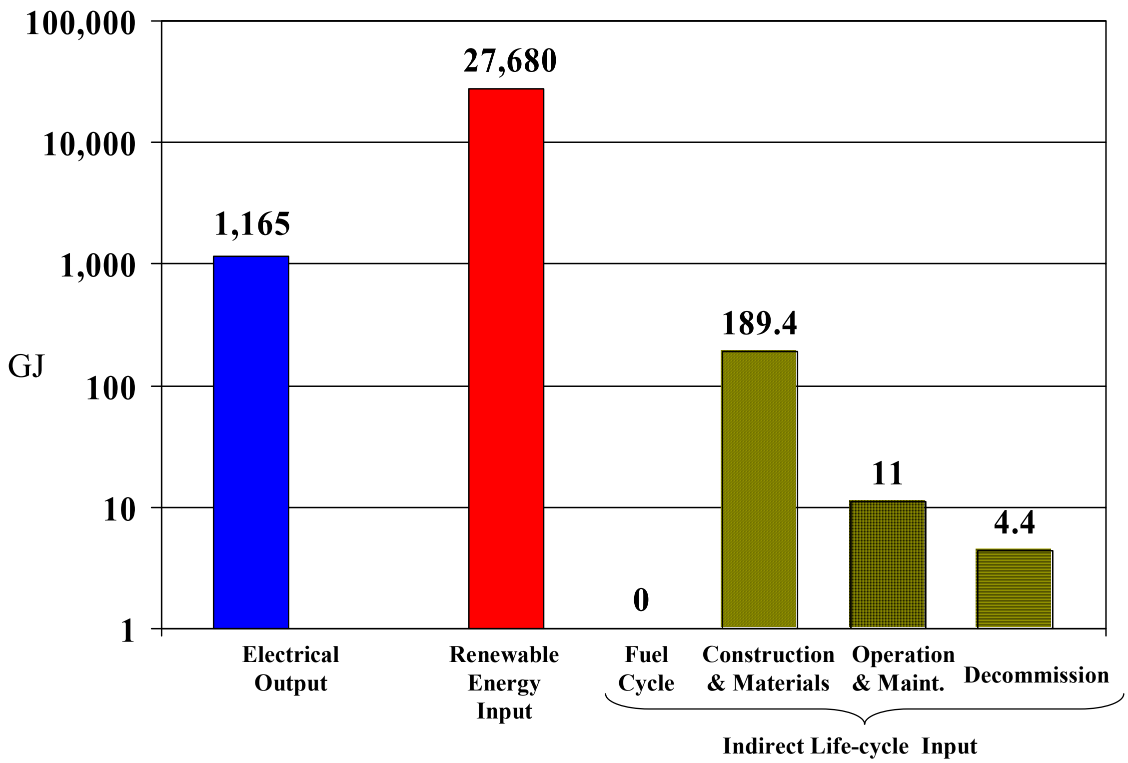


Figure 19: Conventional Module Conversion Efficiency and Life-Cycle Efficiency for an 8 kW Thin Film PV System

Normalized Energy Inputs	
Incident Solar Energy:	27,680GJ$_{th}$
Indirect Life-cycle Input:	205 GJ$_{th}$
Total:	27,885GJ$_{th}$

Life-Cycle Output	
Projected DC Generation:	1,578 GJ$_{th}$
Degradation Losses:	- 120 GJ$_{th}$
Line Losses:	-219 GJ$_{th}$
Inverter Losses:	-74 GJ$_{th}$
Net AC Electrical Output:	1,165 GJ$_{th}$

PV MODULE EFFICIENCY = 1,578 GJ$_e$ / 27,680 GJ$_{th}$ = 5.7%

$$\textbf{LIFE-CYCLE ENERGY EFFICIENCY} = \frac{1{,}165\ GJ_e}{27{,}680\ GJ_{th} + 205\ GJ_{th}} = 4.2\%$$

The low conversion efficiency has a limiting effect on the EPR metric for the PV system. The EPR calculation is illustrated in Figure 20.

Figure 20: Energy Payback Ratio Calculation for an 8 kW Thin Film PV System

Indirect Life-cycle Energy Inputs	
Fuel Related:	0 GJ_{th}
Construction & Materials:	189.4 GJ_{th}
Operation:	11.0 GJ_{th}
Decommissioning:	4.3 GJ_{th}
Total:	205 GJ_{th}

Life-Cycle Output	
Projected DC Generation:	1,578 GJ_e
Degradation Losses:	- 120 GJ_e
Line Losses:	-219 GJ_e
Inverter Losses:	-74 GJ_e
Net AC Electrical Output:	1,165 GJ_e

$$\textbf{ENERGY PAYBACK RATIO} = \frac{\mathbf{1,165\ GJ_e}}{\mathbf{205\ GJ_{th}}} = \mathbf{5.7}$$

6.1.C. Relevance of Energy Metrics

While all energy is treated as equal when performing the NEA, it is important to consider that different types of energy have different qualities due to varied resource availability, cost, environmental impacts, and the potential for alternative uses. The energy-based data and limited environmental data collected for this study are not adequate to compare all technologies unilaterally. This section discusses what meaningful comparisons of energy technologies can be made by exploring limitations of the energy metrics.

Technologies such as wind turbines and PV derive their energy from renewable resources. Because wind and solar radiation are delivered at no cost, with no associated pollution, and with virtually no reduction in the available resource, the "losses" of these resources are essentially inconsequential. It is therefore reasonable and appropriate to use the EPR metric, which excludes the renewable energy inputs (e.g., wind or solar radiation), for internally comparing renewable technologies. Domestic (and global) uranium and lithium resources can be provided at low cost, with limited environmental impact, and with a negligible reduction in the total available resource. Therefore, the EPR metric can be used to compare nuclear technologies internally, and arguably to compare nuclear technologies to renewable technologies. Relative to renewable or nuclear fuel resources, fossil fuels are expensive, environmentally burdensome, and ultimately limited. Therefore, the EPR metric should not be used for the internal comparison of fossil fuel technologies or to compare fossil fuel technologies to nuclear/renewable technologies.

Life-Cycle Efficiency considers the fuel consumed both at the plant and throughout the life-cycle; therefore, the LCE is a meaningful metric for internally comparing fossil fuel technologies. The LCE metric should be used for the comparison of other technologies, if the losses of plant fuel are considered important from an economic, environmental, or other perspective. Enriched uranium has a non-trivial cost, and other environmental impacts, therefore, the LCE metric may arguably be used to compare fossil technologies to nuclear fission operating once-through fuel cycles.[a] If the primary concern is environmental impact or resource limitation, then the LCE metric should not be used for comparing renewable technologies to other alternatives. However, LCE may provide a reasonable measure to compare the performance of

[a] Use of uranium in breeder reactors would greatly expand the energy resource and remove the need for enrichment. A chemical separations plant would have to be included in a breeder economy.

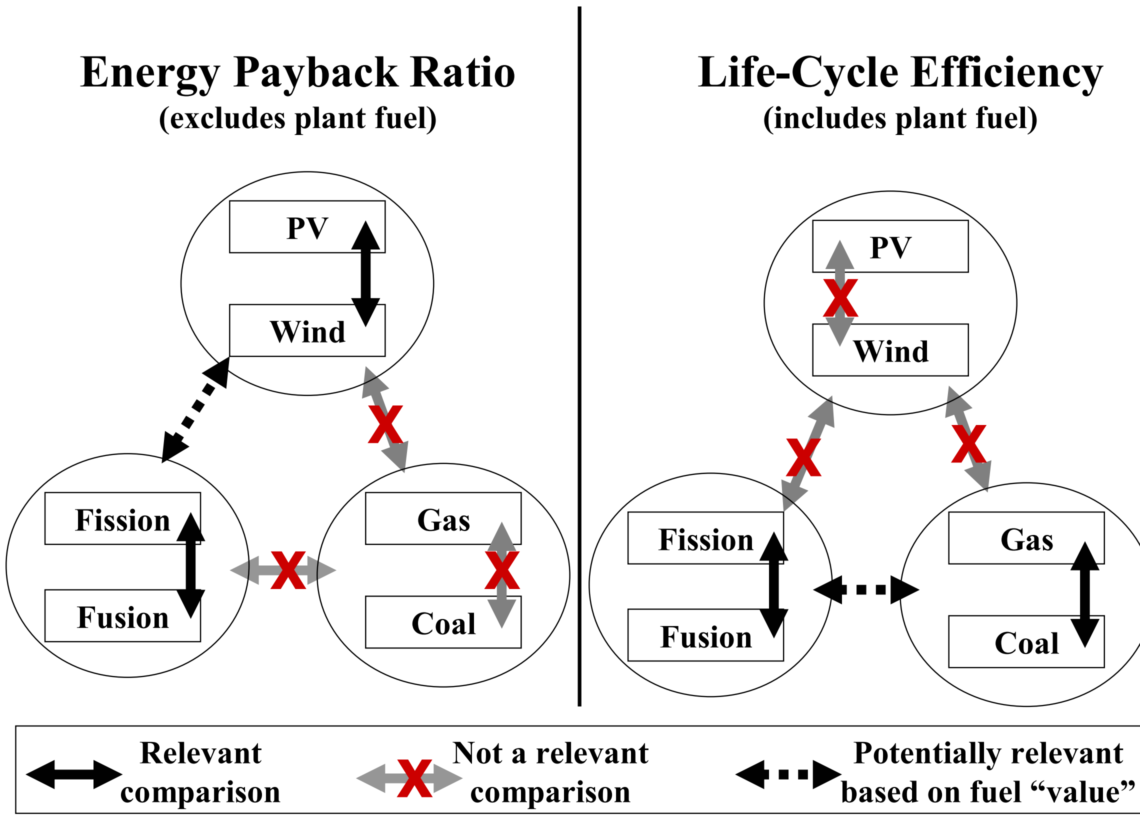
alternatives within a single technology (e.g., comparing mono-crystalline PV performance to amorphous silicon PV performance).

The resource limitations, costs, and environmental burdens of each fuel resource vary by degrees. Further research is warranted which would assign relative values to these (and potentially other) fuel characteristics and create a more comprehensive "value metric" for the unilateral comparison of technologies. Greenhouse gas intensity and energy intensity (as considered in this study) are two parameters worthy of inclusion in the value metric, but these two considerations alone are not adequate to ensure meaningful comparisons across technologies. With these limitations in mind, the energy metric comparisons in Section 6.1.D (Figure 21) are based on the following assertions:

- Renewable energy inputs to the PV and wind systems have no significant cost, environmental burdens, or resource limitations and should be neglected within the energy analysis. Therefore, the EPR metric should be used for the comparison of renewable technologies, and the LCE metric should not.
- Fossil fuels have significant cost, environmental burdens, and resource limitations and should be considered in the energy analysis. Therefore, the LCE metric should be used for the comparison of fossil fuel technologies, and the EPR metric should not.
- The information assembled for this study is not adequate to fully justify the inclusion or exclusion of nuclear fuels in the energy analysis. The use of these resources may arguably be considered insignificant (e.g., based on the vast available resource), in which case using the EPR metric to compare nuclear and renewable technologies is justified. On

the other hand, these fuels may be considered significant in light of other characteristics (e.g., cost), in which case using the LCE metric to compare nuclear and fossil fuel technologies is justified. Regardless of which metric is deemed more appropriate, the nuclear fuels are similar with respect to resource availability, cost, and environmental burden, such that internal comparisons of nuclear fission and fusion technologies are relevant.

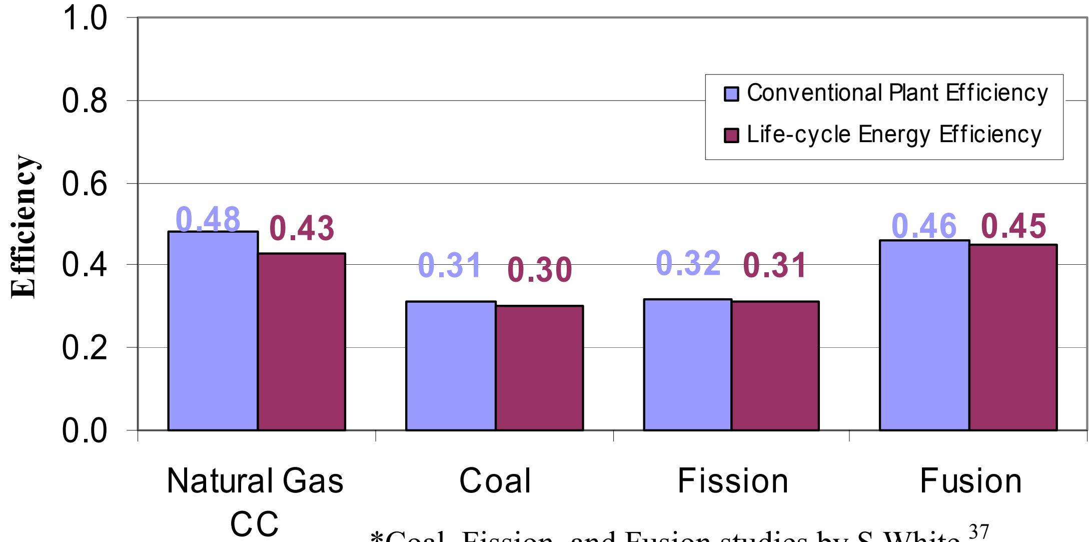
Figure 21: Meaningful comparisons of technologies with the EPR and LCE metrics are difficult because the qualities of the fuel resources vary.



6.1.D. Comparison of Energy Metrics

The life-cycle energy efficiency of fossil and nuclear plants is compared in Figure 22. For coal, fission, and fusion plants, the consideration of life-cycle energy requirements has a small but measurable impact on the overall system efficiency. For the natural gas plant, the consideration of the life-cycle energy requirements is more significant, reducing energy efficiency from 48% at the plant to 43% over the life cycle.

Figure 22: Life-cycle considerations have the most significant impact on the natural gas plant efficiency.*

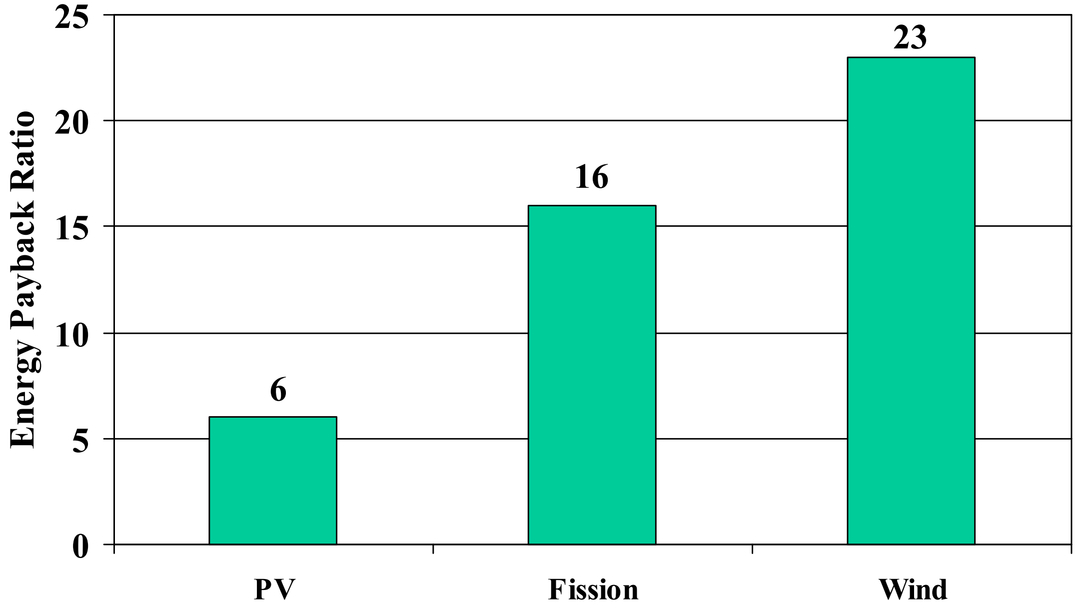


*Coal, Fission, and Fusion studies by S.White.[37]

Figure 23 compares the photovoltaic EPR to previous studies of nuclear fission and wind.

The photovoltaic EPR (6) is limited by the low conversion efficiency of current thin film photovoltaic technology, and is considerably lower than fission (16) and wind (23).

Figure 23: Energy Payback Ratio Comparison to Previous Work [37]



Important distinctions between technologies must be considered when comparing widely differing technologies. One obvious example is the comparison of future technologies to those currently available. A fair comparison between PV and nuclear fusion would require the same time frame. Thin-film photovoltaic is an emerging technology, with conversion efficiencies potentially exceeding 20% in the next two decades.[114] The impact of improvements in conversion efficiency and insolation on the EPR are illustrated in Figure 24. Near future PV is compared to nuclear fusion in Figure 24.

Figure 24: Photovoltaic EPR is correlated to conversion efficiency and insolation.

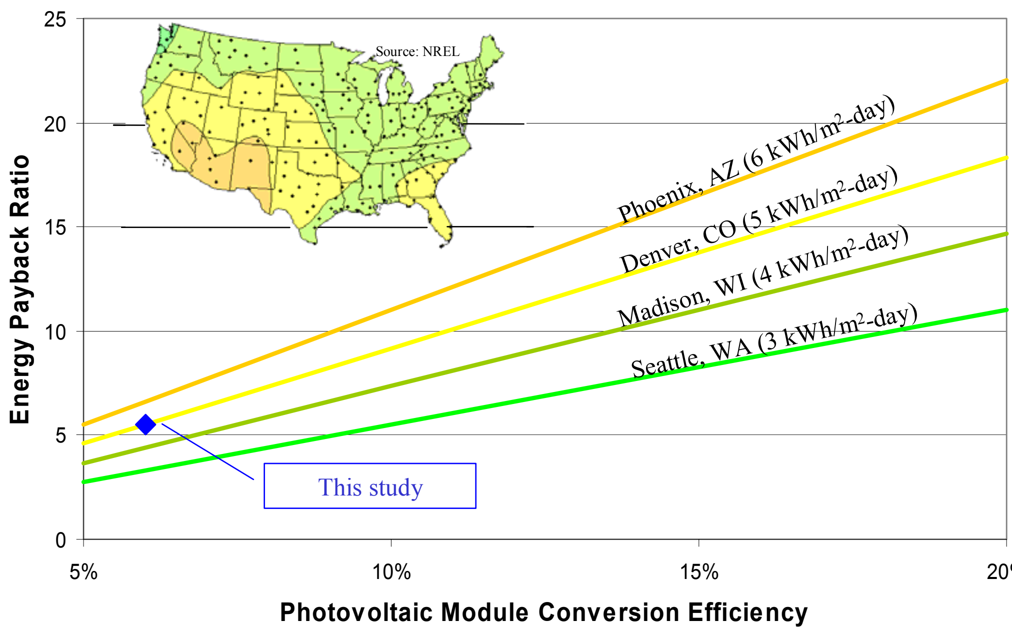
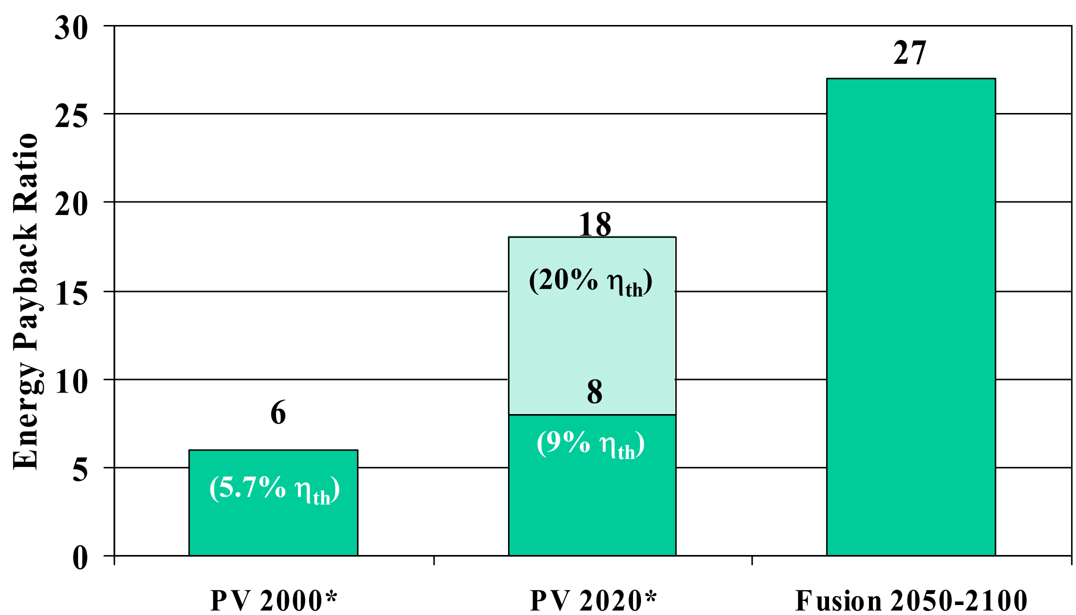


Figure 25: Future improvements in conversion efficiency (9-20%) increase the photovoltaic EPR to between 8 and 18.



*Assumes Insolation Rate of 5 kWh/m^2-day

Utilization differences should also be considered when comparing technologies. Coal, fission, and fusion technologies all assume a plant capacity factor of 75%, while the wind and PV systems have capacity factors of about 30% and 20% respectively. Photovoltaics and wind analysis exclude provisions for electrical storage, which would allow for a continuous power supply and make these systems more comparable to base load systems. Storage considerations would reduce the EPR for wind and PV systems. On the other hand, electricity generated by the PV system could be utilized on site. This is an advantage over centralized power plants, which incur transmission losses prior to end use, in addition to the life-cycle energy requirements of the transmission system. Consideration of transmission would reduce the EPR of centralized generation relative to distributed systems such as the PV system in this study.

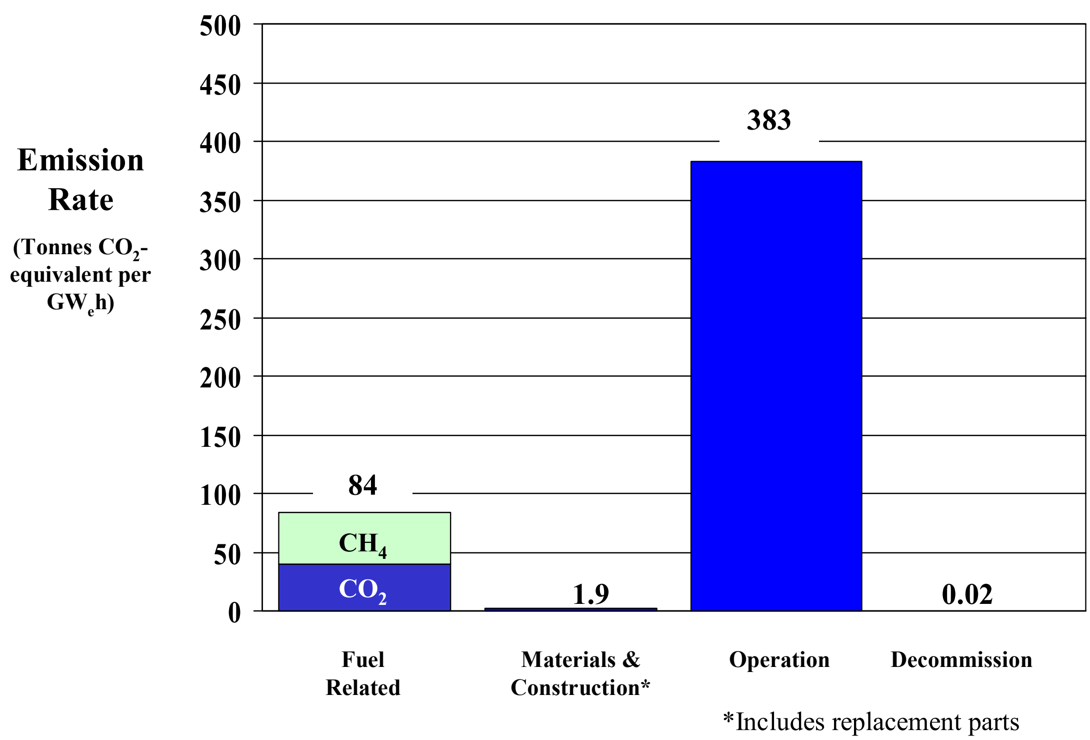
The LCE and EPR metrics incorporate external impacts only as they affect energy requirements (e.g., the energy requirements of waste disposal). There are certainly real impacts imposed by every technology which are not addressed by this methodology, for example, the loss of habitat and biodiversity resulting from mining which may be irretrievable despite land reclamation efforts. The life-cycle NEA is helpful to the consideration of some other external impacts, in particular air pollution emissions.

6.2. Greenhouse Gas Metrics

6.2.A. Natural Gas Plant Greenhouse Gas Emissions

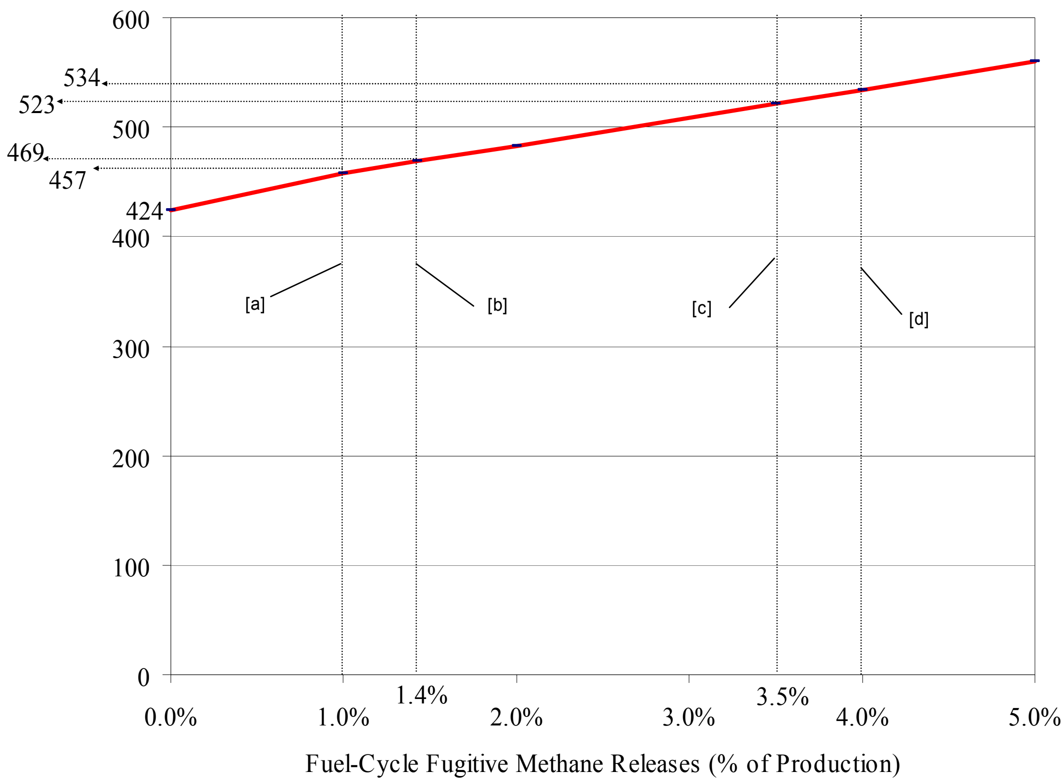
The energy inputs calculated for the natural gas plant NEA provide the basis for calculating greenhouse gas emissions for those facilities. The life-cycle emissions presented in Section 5.1.B are normalized in this section by dividing by the lifetime electrical output, providing an emission factor in terms of tonnes CO_2-equivalent per Gigawatt electric hour (Tonnes CO_2/GW_eh). The normalized emission rate for the natural gas plant life cycle is 469 Tonnes CO_2/GW_eh. As expected, fuel combustion during plant operation accounts for most of the emissions, contributing 382 tonne/GW_eh. However, the fuel cycle also contributes significantly, comprising 18% of the life-cycle emissions, or 84 Tonnes CO_2/GW_eh. Plant construction, O&M, decommissioning, and land reclamation comprise the remaining 1% (5 Tonnes CO_2/GW_eh). Figure 26 illustrates the greenhouse gas emissions from each phase of the life cycle.

Figure 26: Life-Cycle Greenhouse Gas Emission Rate for a 620 MW Natural Gas Plant (Tonnes CO_2-equivalent per GW_eh)



Of the 84 tonne/GW_eh of CO_2-equivalent emissions attributed to the fuel cycle, 44 tonnes/GW_eh are the result of methane leaks, based on USEPA estimates of CH_4 emissions.[83] The assumed leakage rate has a significant impact on the life-cycle emissions, due to the high global warming potential of methane. As stated earlier (See 5.1.B.2), most commonly cited estimates range from 1% - 4%.[104] This range results in significant variability in the life-cycle emission estimates. Figure 27 shows the resulting life-cycle emission rates when using various estimates for methane leakage during the fuel cycle. A 4% rate of fugitive methane releases corresponds to 150 tonnes CO_2-equiv./GW_eh attributed to the fuel cycle and a total life-cycle emission rate of 534 tonnes CO_2-equiv./GW_eh.

Figure 27: Impact of Fuel Cycle Methane Release Rate on Life-cycle Greenhouse Gas Emission Rate for a 620 MW Natural Gas Plant (Tonnes CO_2-equiv. per GW_eh)

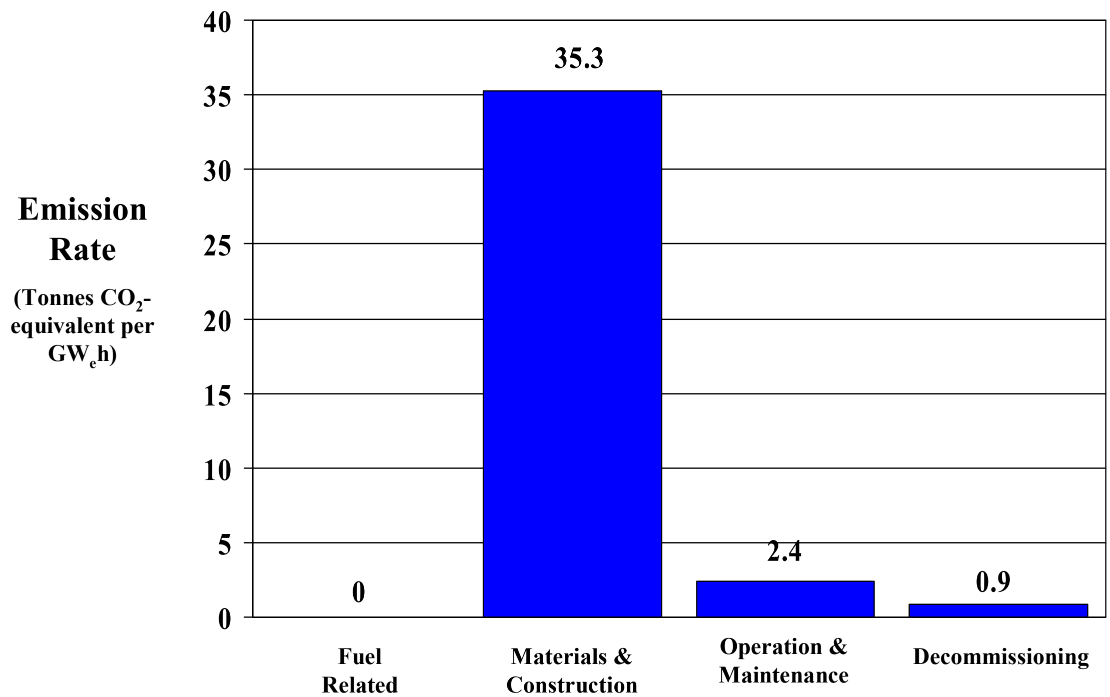


a – Darmstadtler[115] b – U.S. EPA[83] c – Heyes[116] d - Crutzen[117]

6.2.B. Photovoltaic Greenhouse Gas Emissions

Approximately 12.5 tonnes of CO_2-equivalent greenhouse gases are emitted throughout the life-cycle of the PV system (See Section 5.1.B). These emissions are normalized relative to the lifetime electrical output of the PV system and shown in Figure 28. The PV emission has a normalized life-cycle emission rate of 39 Tonnes CO_2–equiv. / GW_eh. The vast majority of the life-cycle greenhouse gas emissions (91%) are associated with materials and construction, in direct correlation to energy consumption. Operation and maintenance contribute another 6% and decommissioning contributes 2% of life-cycle emissions.

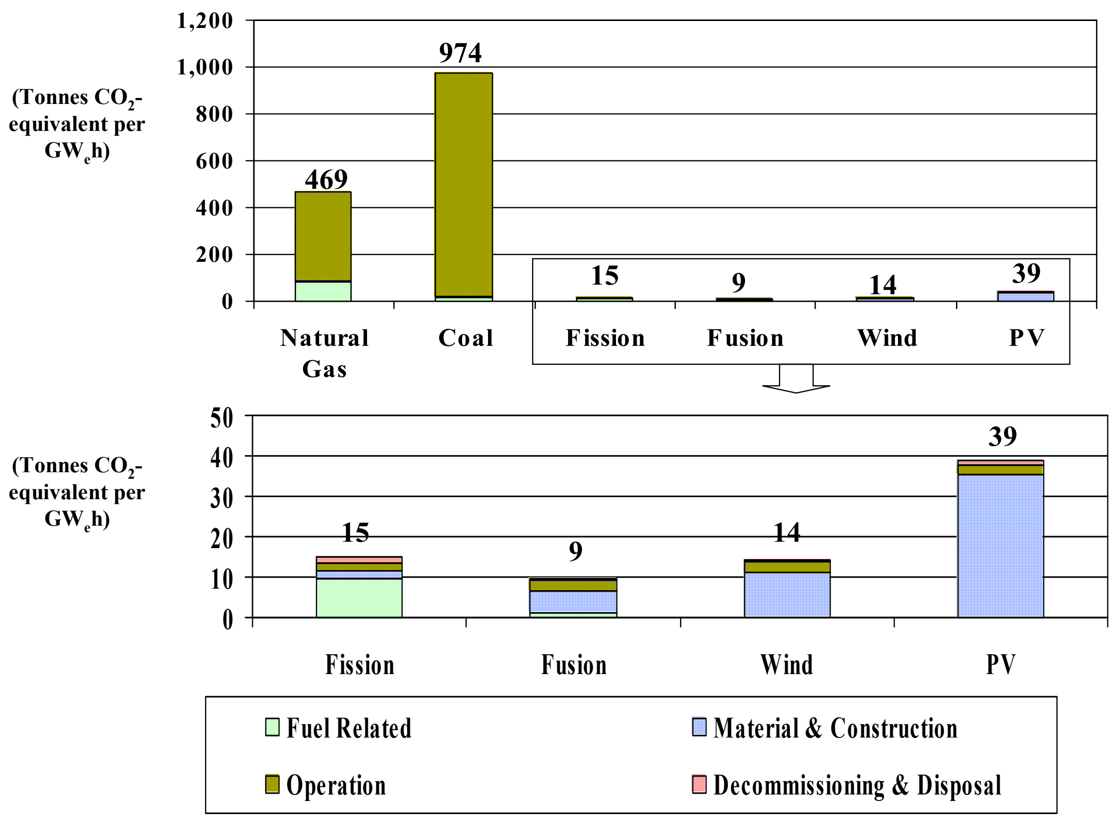
Figure 28: Life-Cycle Greenhouse Gas Emission Rate for an 8 kW Thin Film PV System (Tonnes CO_2-equivalent per Gigawatt-hour)



6.2.C. Greenhouse Gas Emission Rate Comparison

The normalized greenhouse gas emission factor for the natural gas plant and PV system are compared against alternative technologies in Figure 29. Carbon dioxide is the byproduct of coal and natural gas combustion, resulting in high emission rates for these technologies. Life-cycle emissions for fission, fusion, wind, PV are due to external reliance on fossil fuels only, and are drastically lower than those of coal and natural gas plants.

Figure 29: Emission Rate Comparison to Previous Work[37] (Tonne CO_2-equivalent per GW_eh)



*Coal, Fission, Fusion, and Wind analysis by S.White.[37]

The life-cycle emission rate for the natural gas plant (469 Tonnes CO_2-equiv./GW_eh) is significantly lower than the life-cycle emission rate for conventional coal (974 Tonnes CO_2-equiv./GW_eh). Considering only the emissions from power plant fuel combustion, CO_2 emissions from the natural gas plant are 40% of those from the conventional coal plant. A complete life-cycle assessment, however, increases the natural gas plant emission rate more dramatically than the coal emission rate.[37] The resulting natural gas plant life-cycle emission rate is 48% of the life-cycle emission rate for conventional coal.

Photovoltaic, wind and fusion technologies have similar life-cycle emission profiles. The majority of greenhouse gases for these technologies are generated from materials and construction, with some contribution from O&M and minimal emissions from decommissioning. In contrast, the majority of emissions from fission plants are associated with fuel cycle energy requirements (e.g., for enrichment of ^{235}U content). Fission also has relatively significant emissions associated with decommissioning and waste disposal. The emission rate for PV (39 Tonnes CO_2/GW_eh) is higher than fusion (9), wind (14), and fission (15). Because the PV conversion efficiency is directly related to the emission rate, a comparable PV system with 12% conversion efficiency would have an emission rate of only 19 Tonnes CO_2/GW_eh (Figure 30). Future improvements in PV conversion efficiency will reduce the greenhouse gas emission rate as shown in Figure 30.

Figure 30: Effect of PV Conversion Efficiency and Insolation on the Greenhouse Gas Emission Rate (Tonnes CO_2-equivalent per GW_eh)

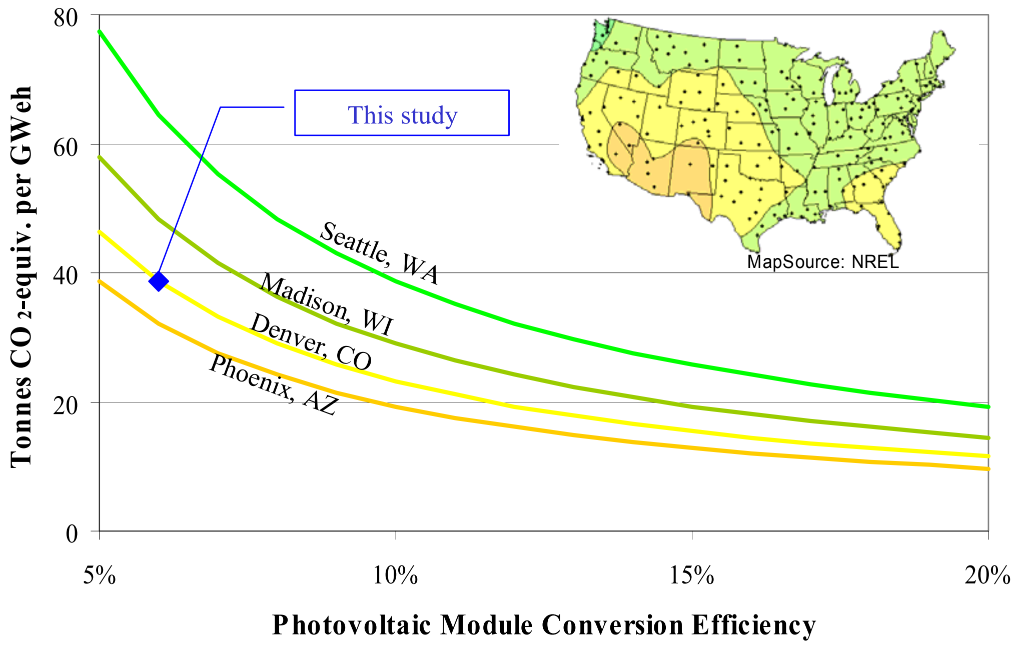
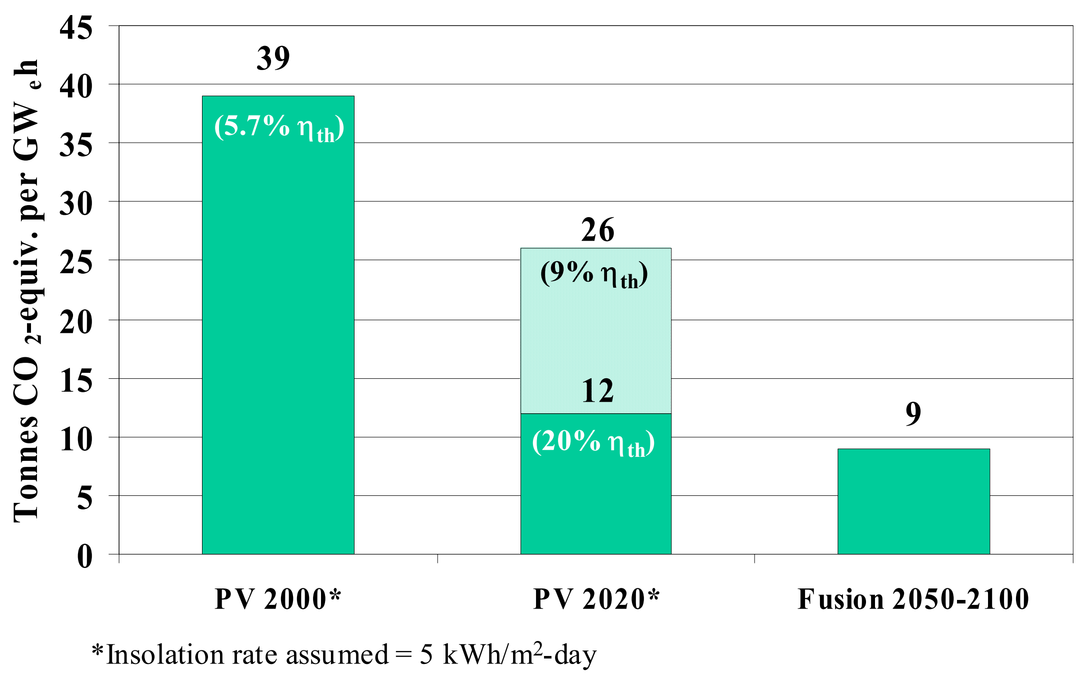


Figure 31: PV greenhouse gas emission rate decreases in the future based on improvements in the conversion efficiency.



Greenhouse gas emissions from nuclear and renewable technologies occur as a result of their reliance on the U.S. fossil fuel infrastructure. For the PV system, the heaviest use of fossil fuels occurs with the consumption of electrical energy during manufacturing. The United States generates 70% of its electricity from fossil fuels. As the U.S. electrical generating profile changes, so will greenhouse gas emissions for nuclear and renewable technologies. Reducing fossil fuel reliance would lower the emission rate for these technologies.

6.3. Policy Analysis

Section 4.3 establishes the methods for ternary analysis of fuel-switching alternatives to meet greenhouse gas emission targets. Three examples are developed in this section.

1. Meeting Kyoto emission objectives in a moderate growth scenario, using:

   A) fuel switching to natural gas exclusively, and

   B) fuel switching to nuclear/renewable exclusively.

2. Meeting the goal set forth by the White House-proposed Global Climate Change Initiative.

3. The impact of fuel-switching for Kyoto compliance on sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions.

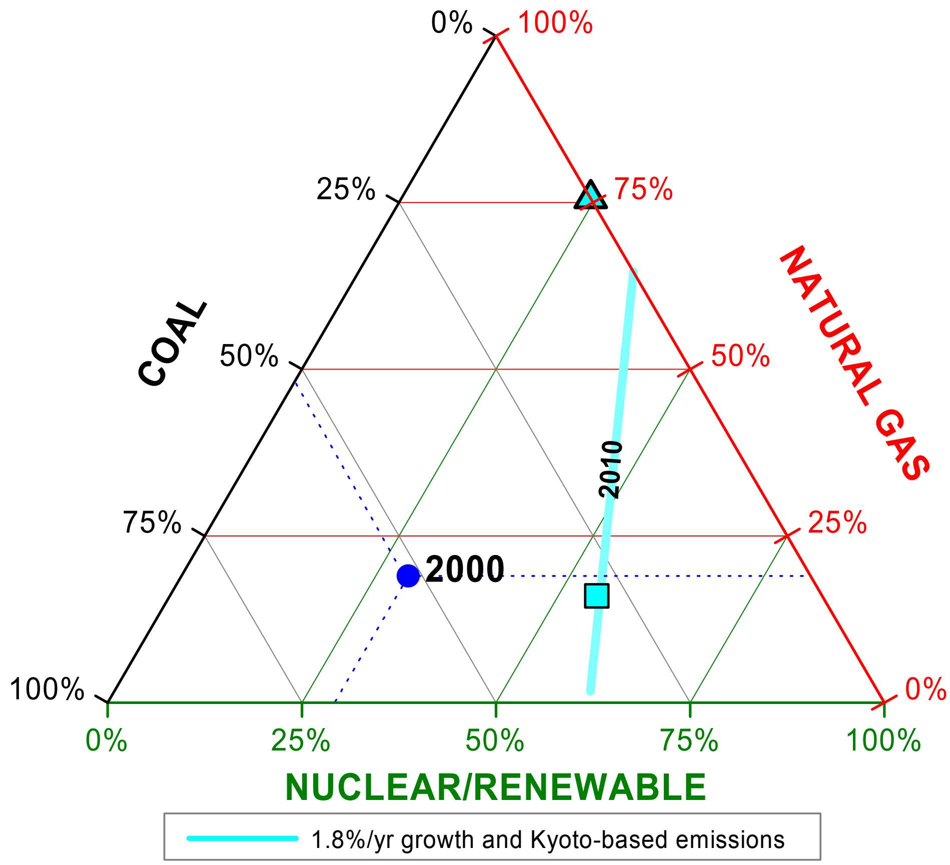
6.3.A. Kyoto-Based Emission Compliance

Figure 32 is a plot of an emission target line for meeting a Kyoto-based emissions (7% below 1990 emissions) with 1.8% annual growth[118] in electricity consumption through 2010. Two alternatives are evaluated in this scenario. Alternative A (▲) attempts to meet the emission target by switching from coal to natural gas. Alternative B (■) attempts to meet the emission target by switching from coal to nuclear and renewable sources.

Figure 32: Evaluation of Fuel-Switching Alternatives with the Ternary Diagram

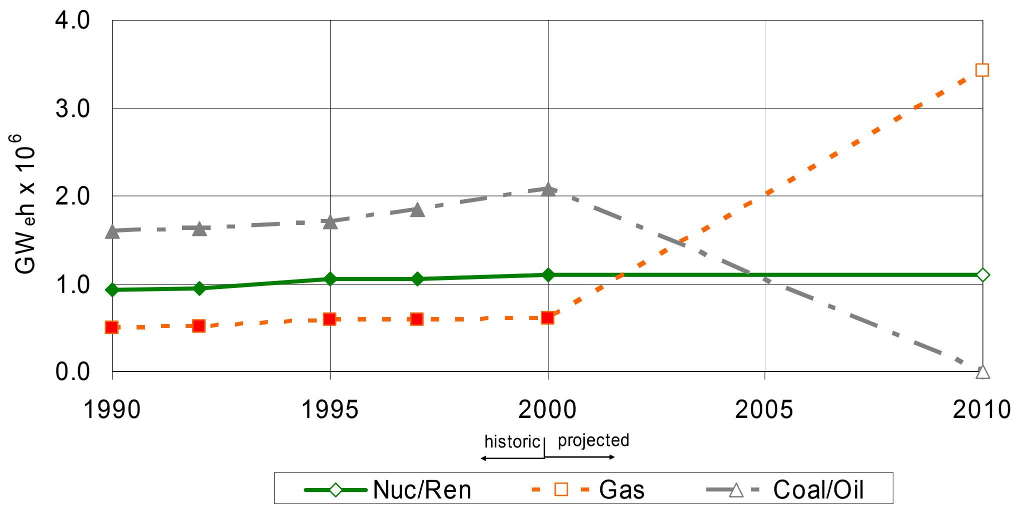
▲ Alternative A – Fuel switching from coal to natural gas with no increase in current Nuclear / Renewable capacity.

■ Alternative B – Fuel switching from coal to nuclear/renewable with no increase in natural gas capacity.



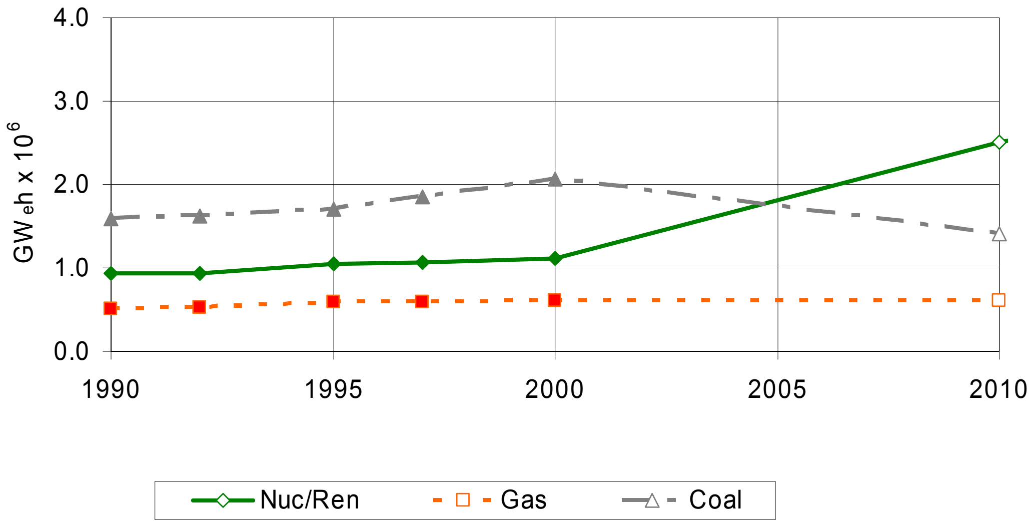
Implementing Alternative A means that new generation is supplied with natural gas and that coal will be replaced with natural gas as necessary to meet the emission target. The amount of electricity generated from nuclear and renewable sources remains constant, but comprises a decreasing percentage of the total mix due to continued growth (1.8%/yr) in total generation. The maximum possible implementation of this alternative is the complete replacement of coal for natural gas. Even with no coal in the fuel mix, this scenario fails to reduce emissions to the Kyoto levels and the resulting fuel mix (▲) does not reach the emission target line in Figure 32. This alternative is shown on a conventional time plot in Figure 33.

Figure 33: Alternative A requires complete replacement of coal as a fuel resource and fails to meet a Kyoto-based emission target.



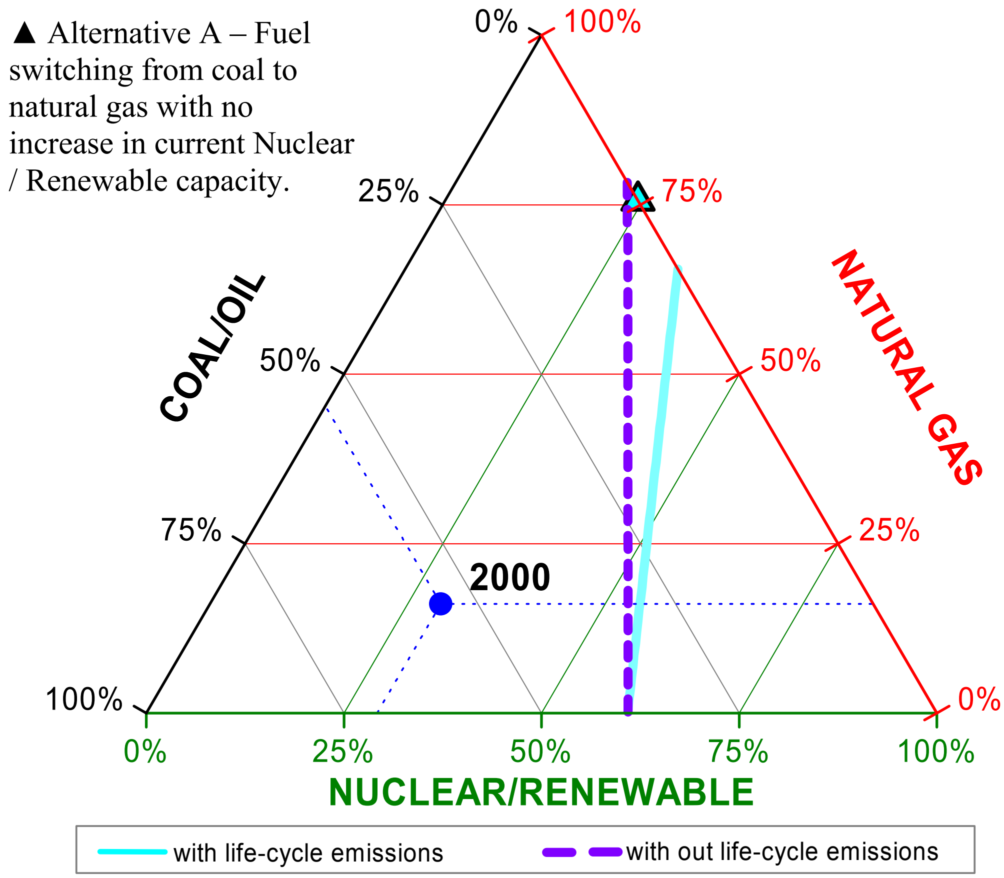
Alternative B supplies new generation from nuclear or renewable sources and replaces coal contributions as necessary to meet the emission target. Absolute contributions from natural gas are maintained at 2000 levels, but provide a decreasing share of the total mix due to overall growth in total generation. Under this scenario, the coal contribution to the fuel mix is reduced by about 1/3 from 2000 levels. While this alternative requires significant increases in nuclear/renewable generation, it represents a viable alternative for meeting the emission goal, unlike Alternative A. Alternative B is shown on a conventional time plot in Figure 34. It is important to note that these alternatives consider fuel switching only, and neglect other mitigating measures such as carbon sequestration or fuel efficiency improvements. Considerations for further study are discussed in Section 6.5.

Figure 34: Alternative B meets a Kyoto-based emission target by replacing about 1/3 of coal generated electricity with nuclear or renewable sources.



The importance of considering life-cycle emissions for policy analysis is demonstrated in Figure 35. As in Figure 32, the emission target represents Kyoto-based emission levels with 1.8% annual growth in electricity consumption through 2010. Two emission target lines are plotted, one using life-cycle emissions, and one using plant emissions alone (neglecting life-cycle emissions other than plant fuel combustion). The target line that neglects life-cycle emissions shifts significantly, such that Alternative A (fuel switching from coal to gas) reaches this emission target line. This shift is due primarily to a 23% reduction in the natural gas emission rate. In this example, neglecting life-cycle emissions may result in the mistaken conclusion that fuel-switching from coal to gas would meet the emission objective.

Figure 35: Consideration of life-cycle emissions significantly affects the evaluation of Alternative A (fuel switching to natural gas).



New construction of high-efficiency combined-cycle gas plants will improve the average performance of U.S. natural gas plants. This will decrease the greenhouse gas emission rate for the natural gas axis in the ternary illustration and improve the viability of Alternative A (fuel-switching to natural gas). The average thermal efficiency of U.S. natural gas generation was 36% in 1998.[91] Improving the average natural gas efficiency to 48% would represent a drastic improvement over a decade, but provides an upper bound for the ternary evaluation of Alternative A. Figures 36 and 37 illustrate the implementation of Alternative A with an assumed improvement in natural gas efficiency.

Figure 36: With greatly improved thermal efficiency, Alternative A (natural gas fuel-switching) becomes a viable option for meeting a Kyoto based emission target.

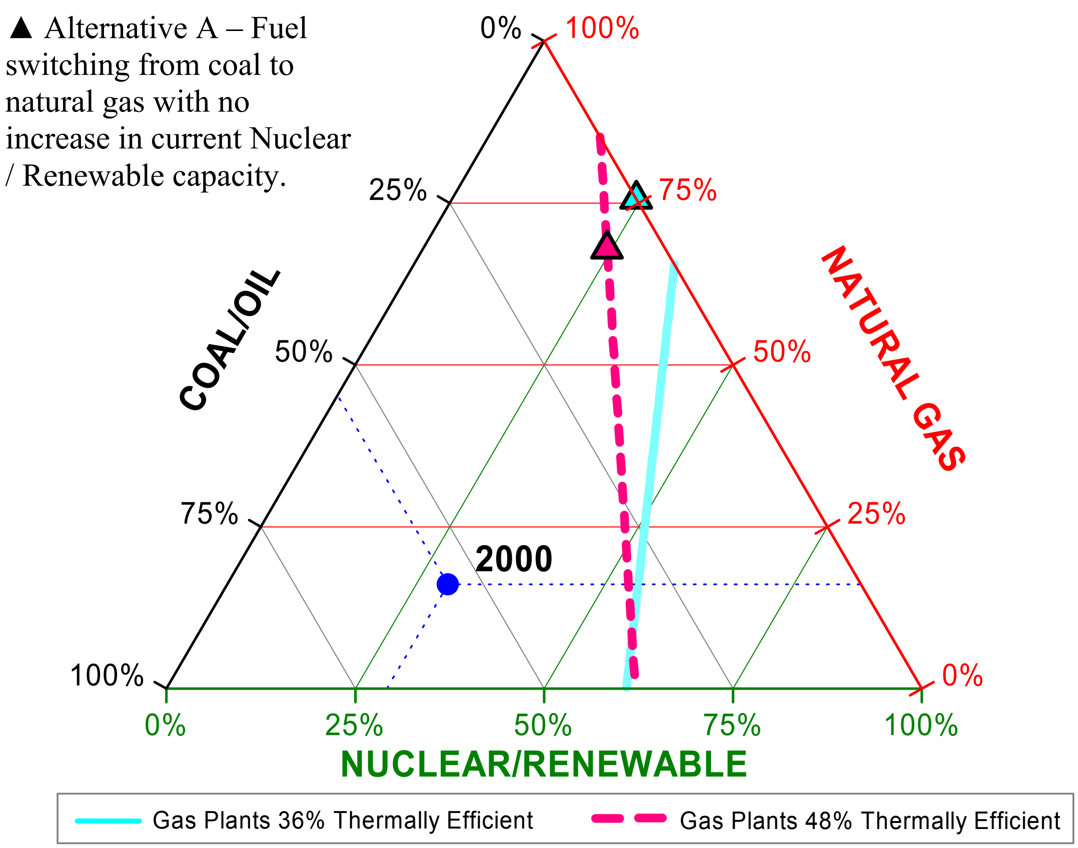
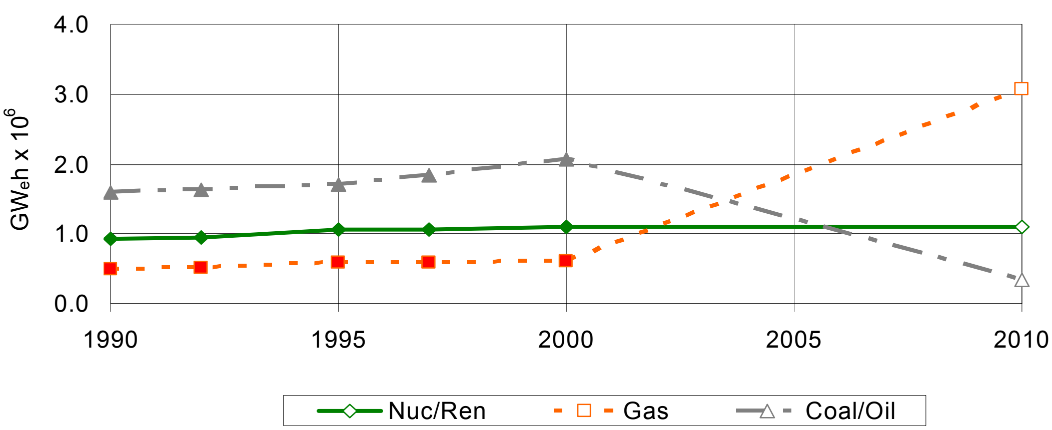


Figure 37: Implementing Alternative A with high efficiency natural gas requires an 83% replacement of coal generation to meet a Kyoto-based emission target.



6.3.B. White House Global Climate Change Initiative

In February of 2002, President Bush proposed a new approach to climate change policy which would use as its benchmark greenhouse gas intensity in terms of tons of emissions per dollar GDP. Bush's Global Climate Change Initiative set as a national goal reducing the greenhouse gas intensity of the U.S. economy by 18% between 2002 and 2012.[23] This initiative is evaluated here using Energy Information Agency projections for growth in GDP (3%) and electricity consumption (1.8%).[118] The projected growth in GDP corresponds to a 38% increase between 2001 and 2012. Under the Bush initiative, greenhouse gas emissions would be allowed to increase by 14% over 2000 levels and still meet the 18% reduction in greenhouse gas intensity.

Figure 38 plots emission target lines for the Bush initiative and the Kyoto Protocol using the ternary method. Allowable emissions under the Bush initiative are 54% higher than the proposed U.S. commitment under the Kyoto proposal. Therefore, the degree of fuel switching required to comply with the Bush initiative are minimal in comparison to the fuel switching required to meet the Kyoto-based objective. Figure 38 shows the emission estimates for compliance with a Kyoto-based target and the Bush initiative.

Figure 38: Minimal fuel switching is required to comply with the Bush Climate Change Initiative by 2012.

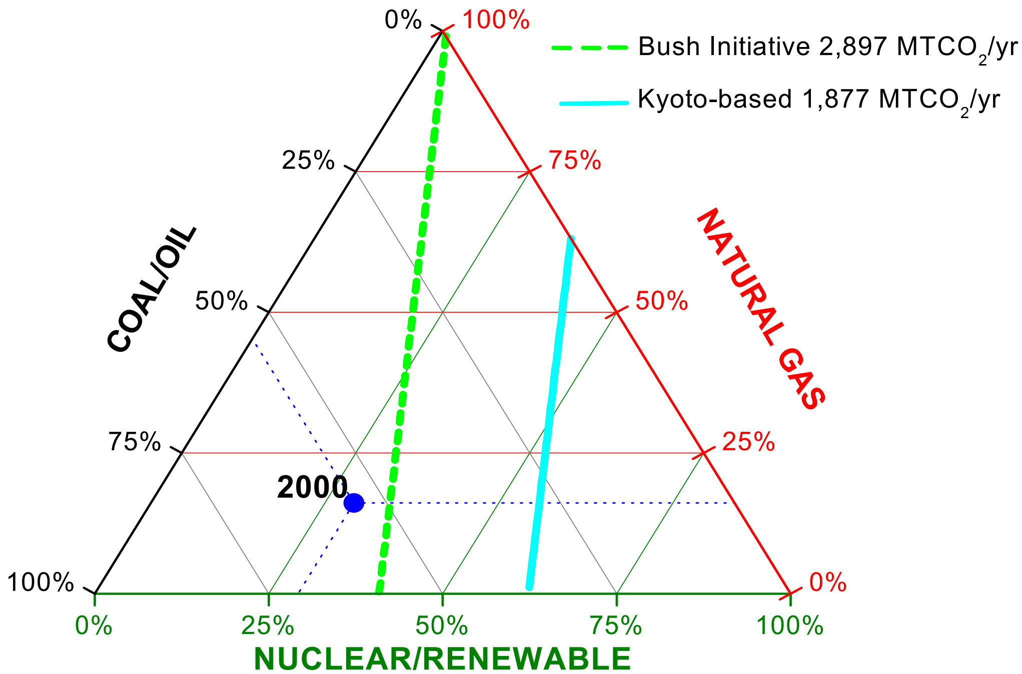
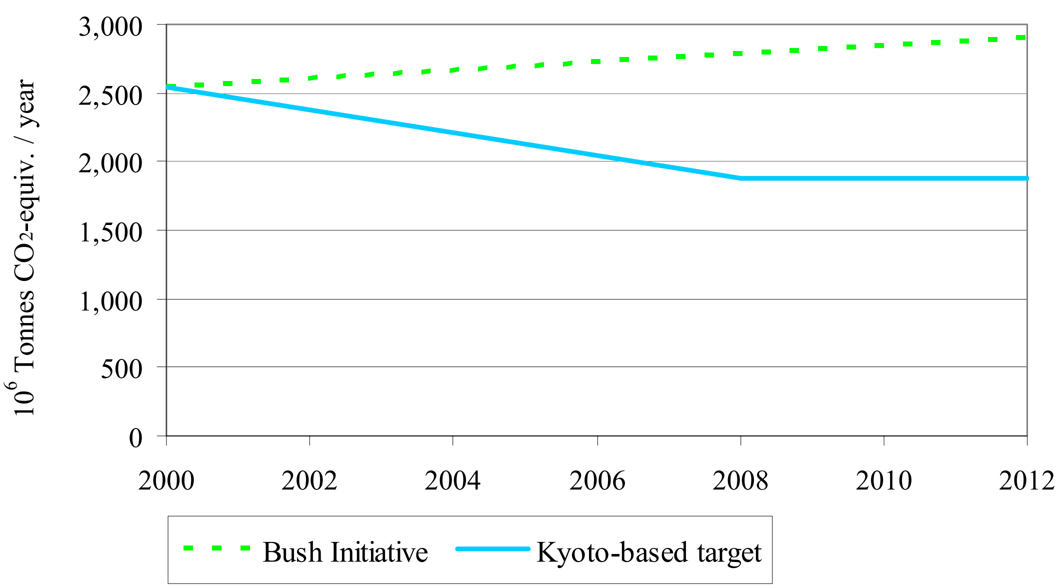


Figure 39: Bush Climate Change Initiative allows greenhouse gas emissions from the electric industry to increase.*



*3% annual growth in GDP and 1.8% annual growth in electricity consumption.

6.3.C. Secondary Considerations

Secondary considerations may also be included on the ternary plots by applying a color scale to the emission target line. This section illustrates two examples of secondary considerations by incorporating emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) into the ternary diagram.[b] Sulfur dioxide and NO_x are the two regulated pollutants for electric utilities under Title IV of the Clean Air Act. Title IV establishes a limit on the total SO_2 emissions from electricity generation at about half of the amount emitted in 1980. The regulation also controls NO_x emissions by regulating an allowable emission rate per fuel input (e.g., kg NO_x emitted per MJ coal input) for certain electric utility boilers at about 73% percent of 1990 emission rates.[119]

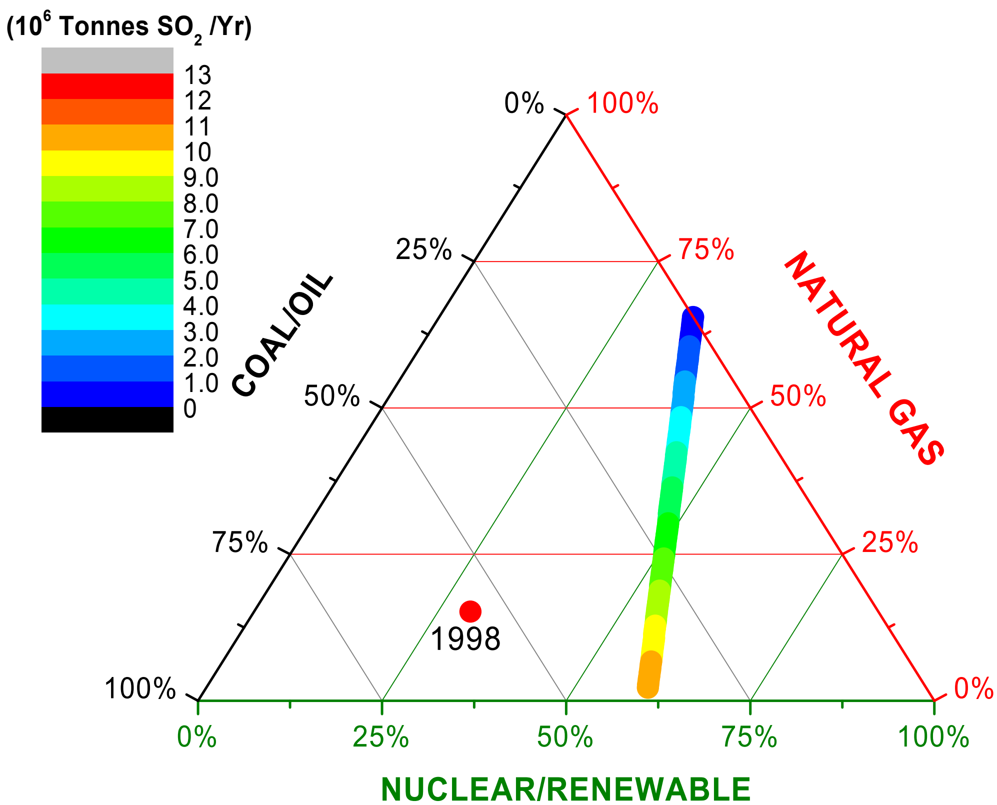
In the ternary plot, differences in emissions for these two pollutants are shown using a color scale along the greenhouse gas target line. The color corresponds to the annual emission rate for each pollutant based on the fuel mixture utilized. Emission rates are estimated for coal and natural gas based on average 1998 U.S. emission rates, the latest currently available data in EPA's E-GRID database.

Sulfur dioxide emissions at each point of the greenhouse gas emission target line are shown in Figure 40. The emission target line in this plot is based on a Kyoto-based emissions and 1.8% growth in electricity consumption through 2010. The SO_2 emissions of the Kyoto-compliant alternatives range from 0.1 million tonnes per year (using no coal) to 10.7 million tonnes per year (using no natural gas). The SO_2 emission rates depend on the amount of coal used, which

[b] This section illustrates the impact of fuel-switching on SO_2 emissions and does not consider the global cooling effect associated with sulfur oxides.

has a much higher average emission rate (6.3 Tonnes SO_2 / GW_eh) than natural gas (0.05 Tonnes SO_2 / GW_eh). The range of NO_x emissions plotted in Figure 40 is lower in all cases than the 1998 U.S. emission rate of 12.6 million tonnes per year.

Figure 40: Fuel-switching for greenhouse gas emission reduction results in a simultaneous reduction in sulfur-oxide emissions.



1998

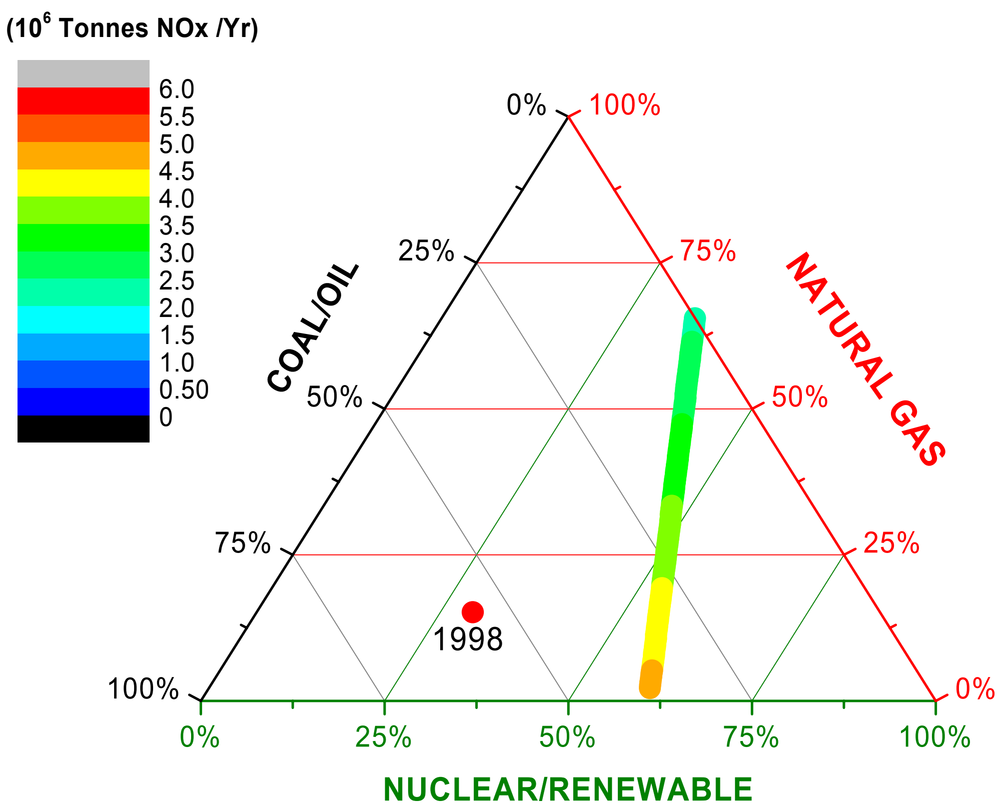
SO_2 Emission = 12.6 Million Tonnes

Using the same methods as in Figure 40, NO_x emissions are color-plotted on the emission target line in Figure 41. Natural gas emission rates for NO_x emissions are significantly higher than for

SO_2, which changes the gradient of the color plot considerably. NO_x emissions range from 2.4 million tonnes per year (using no coal) to 4.6 million tonnes per year (using no natural gas). The range of NO_x emissions plotted is lower than the 1998 U.S. emission rate of 5.7 million tonnes per year.

Reducing SO_2 and NO_x pollution is an external benefit to carbon emission reduction. Additional considerations which may be incorporated into the ternary analysis are discussed in Section 6.5.

Figure 41: NO_x reductions from the electric industry are an external benefit of meeting Kyoto-based emission targets for the electric industry.



1998 NO_x Emission = 5.7 Million Tonnes

6.4. Comparison of Results to Previous Studies

6.4.A. Comparison of Life-Cycle Assessment Results

The estimated emission rate from the natural gas plant for this study (469 Tonnes CO_2/ GW_eh) is slightly higher than previously published studies by Audus (410 Tonnes CO_2/GW_eh),[52] Macdonald (410 Tonnes CO_2/GW_eh),[51] and Wilson (367-459 Tonnes CO_2/GW_eh).[54] The previously published reports exclude many of the indirect energy inputs considered in this study. Higher emission rates are reported by Spath and Mann (499 Tonnes CO_2/GW_eh) and Martin (505 Tonnes CO_2/GW_eh). Spath and Mann's estimates of fuel cycle emissions are 40 Tonnes CO_2/GW_eh higher than in this study (Table 22).[44] Martin has lower estimates of methane emissions than this study, and the higher emission rate is likely due to plant thermal efficiency.[55] The Spath and Mann report was published the same month as Meier and Kulcinski and evaluated identical combustion turbines. Results of these studies are similar and summarized below.

Table 22: Comparison of Combined-Cycle Natural Gas Studies (Tonnes CO_2-equiv. per GW_eh)

Component	**Spath and Mann[44] (2000)**	**Meier and Kulcinski[45] (2000)**
Fuel cycle	124	84
Power Plant Operation	373	383
Construction and Decommissioning	2	2
Total Life-cycle Energy Input	**499**	**469**

The energy requirements for amorphous silicon module production (for PV power) are reported in the literature between 710 to 1,980 MJ/m^2 over widely varying study parameters.[57] Systems similar to that studied here were analyzed by Alsema and Niewlaar,[56,57,58] Martin,[55] Tahara,[66] and Yamada.[65] Alsema and Niewlaar report energy requirements of 1,180 and 1,200 MJ/m^2. These values consider module production only, and exclude final product transport, installation, maintenance, and disposal. Module manufacturing for the PV system researched in this study required an estimated 1,100 MJ/m^2 including engineering, administration, and final transportation to site.[60,57] Consideration of the remaining life-cycle components (balance of system, installation, maintenance, and disposal) increased the total energy requirements to 1300 MJ/m^2 in this study. The Energy Payback Ratio is also reported by Voorspools[63] and Oliver[59]. Voorspools reports an EPR between 1.2 and 2.4 for mono-crystalline modules. Oliver's study reports an EPR for building-integrated PV systems of 1.24. Little documentation is available defining the type of system studied.

The Energy Payback Time is a frequently used measure. The PV system researched for this study has an estimated energy payback time of 5.3 years using an average output after adjusting for system degradation. Payback times in the literature range from 1.1 to 13 years over widely varying technologies and parameters. Yamada studied a comparable system and reported a payback time of 6.3 years.

Greenhouse gas emission rates for Alsema and Niewlaar's systems are identical to the emission rate in this study (39 Tonnes CO_2/GW_eh) after converting to equivalent (i.e., U.S.) emission factors. Martin reports a slightly lower emission rate (33 Tonnes CO_2/GW_eh).[55] Yamada and

Tahara[c] report emission rates that are out of range of the other comparable studies on amorphous silicon. Yamada reports a range of 103 to 227 Tonnes CO_2/GW_eh under three scenarios of module production scale. Tahara reports a comparably high range of emission rates from 150 to 190 Tonnes CO_2/GW_eh.

6.4.B. Comparison of Policy Applications for LCA Results

The NEA literature discussed above does not develop a basis for the policy relevance of energy metrics. However, comparisons of energy metrics may offer insight into preferred electricity generating alternatives. A good example is Alsema's reporting of the higher energy efficiency of frameless building-integrated PV systems in comparison to conventional array supported PV. Net energy results are frequently performed in conjunction with estimating life-cycle greenhouse gas impact, which has an obvious application to policy analysis. This research is interested in greenhouse gas mitigation strategies for the electric industry, and in particular LCA of fuel substitution strategies. The results of several comparable studies listed in Section 3.4 are described below.

- Hammons[72] evaluates the role of renewable technologies and high-efficiency gas turbines for climate change mitigation and predicts that approximately half of new construction will utilize gas turbine technology.

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[c] It is possible that this discrepancy is due to an error in the reporting nomenclature between carbon (C) and carbon dioxide (CO_2). Assuming these values were intended to be reported in terms of CO_2, the Yamada results (28 – 62 Tonnes CO_2/GW_eh) and the Tahara results (40 – 52 Tonnes CO_2/GW_eh) are within range of other studies.

- Ito[69] incorporates an LCA approach to evaluate five scenarios for long term energy supply. Ito concludes that a renewable-intensive scenario with appropriate nuclear content achieves carbon reductions, but states that the nuclear-intensive scenario is attractive from an economic, environmental and risk standpoint.
- Hayhoe[74] discusses the importance of incorporating methane emissions from the natural gas fuel cycle into U.S. greenhouse gas reduction targets.
- Hoffert[70] predicts the global carbon-free generating capacity required for CO_2 stabilization and estimates that worldwide, 20 and 46 Terawatts of carbon-free generating capacity is required for atmospheric CO_2 stabilization at 350 and 750 ppm_v CO_2 respectively.
- Kydes[75] evaluates supply side alternatives for CO_2 emission reduction in the U.S. and reports that none of the scenarios examined stabilized emission by 2015.
- Knapp[73] evaluates the time requirements for new electricity technologies to replace fossil fuels and the resulting carbon impact. Using a low-nuclear and maximum renewables case, 75% of the electric generation was non-carbon by 2060, but only 30% of generation was non-carbon by 2040. This slow market penetration results in only a small (18%) reduction in cumulative emissions from the base case and fails to stabilize world carbon emissions.
- Bernow[76] evaluates U.S. generating mix alternatives under a capped carbon scenario for the U.S. Bernow reports that emission reductions of 18% below 1990 levels were achieved with 1.4% annual growth in electricity and required reducing coal 40%, increasing gas 33%, and increasing non-hydro renewables by 600%.

- Roehrl[71] evaluates four high growth scenarios for carbon stabilization: clean coal, gas and oil, solar and nuclear, and balanced. Roehrl reports that clean coal was the least economic means of carbon stabilization and solar/nuclear the most economic.
- The Wisconsin Department of Natural Resources[77] studied multiple measures for reducing greenhouse gas emissions and reported that state emissions could be reduced by 21 million tons in 2010 by switching coal-fired power plants to natural gas.

Several studies evaluate fuel-switching alternatives in foreign countries and are summarized below.

- Malaysian regulations have forced electric utilities to switch from the current fuel mix (70% gas, 15% coal, 10% hydro, and 5% petroleum) to a new mix of 40% gas, 30% hydro, 29% coal, and 1% petroleum by 2020. Masjuki[78] reports that the cumulative greenhouse gas emissions from the conversion are 3% lower than a business as usual scenario. However, the high growth projected for Malaysian electricity consumption results in a tripling of annual greenhouse gas emissions.
- Syri[79] analyzes electricity generation fuels for two Kyoto compliant scenarios in Europe and compares them to a baseline scenario. By 2010, nuclear and renewable generation increased by 48% in the baseline scenario, 64% in the Kyoto-compliant scenario without carbon trading, and 56% in the Kyoto-compliant scenario with carbon trading.
- Chedid[80] compares a natural gas fuel substitution to a renewable fuel substitution for Lebanon and reports the emissions results from 36 scenarios.

- Wang[81] and Zhang[82] evaluate fuel substitution strategies for China. Wang assesses the long term viability of switching from coal to natural gas for compliance with Framework Convention on Climate Change provisions. Zhang compares switching to hydroelectric and the switching to nuclear versus improving coal conversion efficiency by using larger plants. Zhang reports large reductions in CO_2, but high capital investments for the hydroelectric and nuclear options.

7. Conclusions

1) Life-Cycle Assessment (LCA) provides a better understanding of the energy and environmental performance of electricity generation systems. A 620 MW combined-cycle natural gas plant that is nominally 48% thermally efficient was shown to be only 43% energy efficient when evaluated across its entire life-cycle. This efficiency reduction was due almost entirely (95%) to energy losses during the natural gas fuel cycle. The performance of an 8kW building-integrated photovoltaic system is also reduced significantly when evaluated over its life cycle. The rated conversion efficiency from sunlight to DC electricity is 5.7%. The sunlight to AC conversion efficiency is 4.3%, when accounting for life-cycle energy inputs, as well as losses due to system wiring, AC inversion, and module degradation.

2) Metrics which consider energy performance in thermal terms alone cannot meaningfully compare all technologies unilaterally, because the value of energy inputs are not equivalent due to varied cost, resource availability, environmental impacts, and potential for alternative uses. While a more comprehensive "value metric" would be beneficial for the unilateral comparison of technologies, relevant use of the EPR and LCE metrics can be summarized as follows:

- The Energy Payback Ratio (EPR) provides a means of internally evaluating renewable or nuclear resources, by comparing the useful electrical energy output to the life-cycle energy inputs, and excluding the primary source of energy used for electrical conversion. The EPR metric may be used to compare renewable technologies to nuclear technologies if the use of primary plant fuel (e.g., wind, sunlight, uranium, lithium) is considered insignificant. The EPR metric cannot be reasonably used for fossil fuels because it neglects the primary fuel use which has significant economic and environmental impacts.

- Life-Cycle Efficiency (LCE) includes the fuel consumed at the plant as well as throughout the life-cycle, providing a meaningful metric for comparing fossil fuel technologies. The LCE metric may be used to compare fossil fuel technologies to nuclear technologies if the use of primary plant fuel (e.g., coal, natural gas, uranium, lithium) is considered significant. The LCE metric should not be used for the comparison of renewable resources, because the losses of the renewable resources are essentially inconsequential.

3) Life-cycle considerations significantly impact the greenhouse gas emission rate for a 620 MW combined-cycle natural gas plant. The emission rate for the natural gas plant life-cycle (469 tonnes CO_2-equivalent per GW_eh), was 23% higher than the emission rate from plant operation alone (382 tonnes CO_2-equivalent per GW_eh). The emission rate may actually be more than 40% higher than the emission rate from plant operation alone, due to methane releases. There is a high degree of variability in published estimates of fuel-cycle methane releases, with commonly cited estimates ranging from 1 to 4% of natural gas production. Because methane is a strong global warming agent, this uncertainty leads to a potential range of emission rates from 457 to 534 tonnes CO_2-equivalent per GW_eh for the studied plant.

4) The life-cycle greenhouse gas emission rate for a photovoltaic (PV) system is shown to be low (39 Tonnes CO_2-equivalent per GW_eh), but not zero. This value is higher than other

nuclear and renewable systems studied previously (using the same approach) by White and Kulcinski[88,89,90], including nuclear fission (15 Tonnes CO_2/GW_eh), wind (14 Tonnes CO_2/GW_eh), and future DT fusion (9 Tonnes CO_2/GW_eh) technologies. While higher than other renewable or nuclear technologies, the PV greenhouse gas emission rate (39 Tonnes CO_2-equivalent per GW_eh) is still insignificant in comparison to the natural gas plant (469 Tonnes CO_2/GW_eh) or the previously studied[37] coal plant (974 Tonnes CO_2/GW_eh).

5) Life-cycle emission rates can be an important consideration in the evaluation of greenhouse gas mitigation alternatives, and provide insight not available by the consideration of plant emissions alone. For U.S. generated electricity, emissions from the natural gas fuel-cycle may be the most important life-cycle consideration outside of combustion of primary plant fuels. Neglecting the natural gas fuel-cycle emissions may lead to inaccurately assessing the viability of fuel-switching measures to meet greenhouse gas reduction objectives within the electric industry.

6) A ternary method of analysis, using average U.S. emission rates from existing plants in conjunction with life-cycle emissions, provides an effective means of comparing greenhouse gas emission reduction scenarios. This method shows that using fuel-switching from coal to natural gas fails to meet a Kyoto-based emission target with moderate growth in electricity consumption, even with a 100% replacement of coal for natural gas. In comparison, only 34% of coal generation requires replacement with nuclear or renewable technologies to meet the Kyoto-based emission objective. The White House's Global Climate Change Initiative is shown to allow for a

14% increase in U.S. greenhouse gas emissions, and annual greenhouse gas emissions that are 54% higher than the proposed U.S. commitment under the Kyoto Protocol.

7) In addition to greenhouse gases, the ternary illustration allows for the evaluation of secondary considerations. Fuel switching for greenhouse gas mitigation has an ancillary impact of on SO_2 and NO_x emissions. The ternary method illustrates that the by using fuel-switching for Kyoto-based compliance, SO_2 and NO_x emissions are simultaneously reduced (i.e., naturally avoided) significantly below 1998 levels.

8 Recommendations for Further Study

1) Additional research can assist in making the energy comparisons more meaningful. Section 6.1.D discusses considerations which prevent a comprehensive comparison of energy metrics between differing technologies. A life-cycle analysis of the transmission and distribution network would aid in properly assessing the energy requirements, losses, and greenhouse gas emissions associated with centralized technologies. This will allow for a more meaningful comparison to distributed technologies such as PV. A life-cycle analysis of energy storage systems would allow for relevant comparisons of intermittent technologies such as wind and PV to dispatchable base-load systems. Intermittent power systems used in conjunction with a backup power system (e.g., a PV system used with a diesel generator) are an alternative to energy storage systems and may be worthy of analysis.

2) As discussed in Section 6.1.C, providing meaningful comparisons of energy metrics across technologies is difficult due to the varied quality of energy inputs. Because NEA segregates energy inputs by fuel type, this analysis may be extended beyond simple thermal energy comparisons and incorporate other energy resource considerations such as availability, cost, and reliability. Incorporating such considerations into a function which applies a “value” to the various energy inputs would yield a more meaningful means for comparing technologies. This analysis may also be extended to include other non-energy considerations (e.g., environmental impacts). The greenhouse gas emission impact assessed in this study is one example of this type of analysis. Other potentially interesting considerations include land use, thermal pollution,

hazardous waste generation, water consumption and impact, and other criteria or hazardous air pollutant emissions.

3) A more sophisticated approach to the ternary analysis would incorporate temporal changes in technologies and calculate unique emission factors for each point on the ternary plot. While the ternary method of analysis offers a flexible approach to evaluating a wide range of policy alternatives, improvements in fossil fuel conversion efficiency are likely to accompany fuel-switching efforts. As a result, the emission factors for the coal and natural gas axes should decrease with time. In addition, alternatives which require significant natural gas plant construction may result in greater emission reductions due to the installation of highly efficient plants. Changes in the electricity fuel mix (e.g., expansion of renewable technologies) will also impact life-cycle emissions and result in slight variations in the emission rate throughout the ternary diagram.

4) Section 6.4 uses a color mapped emission target line to incorporate SO_2 and NO_x emissions into the ternary analysis. Other secondary considerations could also be evaluated using a similar approach. Incorporating the variation of the levelized busbar generation cost along the emission target line would be valuable. In addition to busbar generation costs, other economic considerations (e.g., avoided costs of NO_x control) could be incorporated into a color-mapped cost-benefit analysis.

5) Spatial considerations of power plants in conjunction with fuel choices may be significant from an urban planning perspective. Large power plants produce considerable waste heat which could result in localized warming if this heat is geographically confined. Growing energy use in urban areas has been shown to result in a quantifiable and significant increase in the urban atmosphere temperature (urban heat island effect).[120] This effect exacerbates the impact of global warming and facilitates the formation of ground level ozone. These factors lend weight to fuel choice consideration in policy development. Continued work in this are would require considerable knowledge of heat transfer mechanisms as well as three dimensional air-dispersion modeling.

6) Incorporating time limitations for new plant construction within the ternary method analysis would provide valuable insight into the viability of emission goals. A method for estimating the time requirements for new technology implementation is developed by Knapp.[73] This approach could also be used to quantify the relative contributions of nuclear versus renewable alternatives.

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APPENDIX A

LIFE-CYCLE ASSESSMENT FOR 620 MW COMBINED-CYCLE NATURAL GAS PLANT

DATA AND CALCULATIONS

TABLE A1: SUIMMARY

Life-Cycle Component	**Energy (GJ)**	**Greenhouse Gas Emissions (Tonnes CO_2-equiv.)**	**Reference Tables**
EXPLORATION			
	9,284,606	***655,726***	A3
PRODUCTION, STOARGE & PROCESSING			
Pipeline Material	143,541	499,579	A4 - A5
Pipeline Installation	212,534	14,734	A6 - A8
Production Fuel	75,803,437	6,040,544	A9 - A16
Storage & Processing Fuel	14,041,802	1,661,966	A9 - A16
Subtotal	***90,201,314***	***8,216,824***	
TRANSMISSION			
Pipeline Material	499,579	36,717	A4 - A5
Pipeline Installation	1,129,159	78,259	A6 - A8
Compressor Stations	156,900	11,270	A17 - A18
Transmission Fuel	34,077,881	4,619,972	A9 - A16
Transmission System O&M	441,141	30,934	A19 - A20
Subtotal	***36,304,660***	***4,777,152***	
POWER PLANT MATERIALS & CONSTRUCTION			
Building Materials	125,891	20,737	A21 - A23
Equipment	856,804	61,738	A26
Construction	695,305	48,582	A27
Subtotal	***1,678,001***	***131,057***	
POWER PLANT OPERATION & MAINTENANCE			
Fuel	1,222,857,000	62,220,103	A9 - A16
Operation & Maintenance	3,629,293	251,118	
Replacement Parts	2,374,877	171,941	A28
Subtotal	***1,228,861,170***	***62,643,163***	
DECOMMISSIONING & LAND RECLAMATION			
	59,231	***3,960***	A29 - A31
TOTAL LIFE-CYCLE	**1,366,388,981**	**76,427,882**	
TOTAL LIFE-CYCLE ELECTRICAL OUTPUT	**586,971,360**		A2

ADDITIONAL DATA AND CALCULATIONS	**Page**
PLANT POWER AND ENERGY	A2
INPUT/OUTPUT ENERGY INTENSITY & GREENHOUSE GAS INTENSITY	A32 - A33
GREENHOUSE GAS EMISSION FACTORS	A34 - A36

TABLE A2: PLANT OPERATING ASSUMPTIONS

PLANT POWER AND ENERGY			**Calculation**
Gross Power Output[1]	632,400,000	Watts	A
System Auxiliaries[1]	12,400,000	Watts	B
Net Power Output[1]	620,000,000	Watts	C=A-B
Calandar Year Lifetime	40	years	D
Annual Capacity Factor	75%		E
Full Power Lifetime	30	years	F = D*E
Lifetime Net Electrical Output[2]	**163,048**	**GWeh**	G = C * F * (8766 hrs/yr)
Lifetime Net Electrical Output[3]	**586,971,360**	**GJ**	H = G * (3600 s/hr)
Net Thermal Efficiency[1]	48%		I
Lifetime Natural Gas Input	**1,222,857,000**	**GJ**	J = H / I
PLANT PERCENT CONSUMPTION OF U.S. NATURAL GAS			
Plant Natural Gas Consumed per Calandar Year[2]	805	m^3 x 10^6 / year	K
US Nat Gas Production Delivered to End Users[3]	418,372	m^3 x 10^6 / year	L
Plant Percentage of U.S. Natural Gas Consumption	**0.192%**		M = K/L

References and Notes:

1. Sherman M. (2000) Vice President, Project Development, Aquila Energy, Personal Communications.

2. 805 m^3 x 10^6/ year = (1,222,020,000 GJ) * (1E^9 J/GJ) / (1055 J/BTU) / (1020 BTU/ft^3) / (35.28 ft^3/m^3) / (40 years) / (10^6)

3. Estimate based on 1994 to 1998 average, data from EIA *1998 Natural Gas Annual.* DOE/EIA-0131(98).

TABLE A3
NATURAL GAS EXPLORATION

		Calculation
Average Cost of Adding Proved Reserves1993 - 1998[1] ($/GJ)	$0.72	A
I/O Intensity for Gas Exploration[2] (GJ/$)	0.008940	B
Energy Cost of Exploration (GJ/GJ)	0.006440	C = A * B
Lifetime Fuel Delivery to Plant (GJ)	1,222,857,000	D
Natural Gas Production/Delivery Ratio[3]	1.179	E
Required Lifetime Production (GJ)	1,441,688,122	F = D * E
Plant Exploration Energy Requirement (GJ)	**9,284,606**	G = C * F
I/O Greenhouse Gas Intenstiy (Tonnes CO_2-equiv. / GJ)[2]	0.0706	H
Plant Exploaration Emissions (Tonnes CO_2-equiv.)	**655,726**	I = G * H

References and Notes:

1. The Coastal Corporation. (1998) *1998 Annual Report* . Houston, TX.
2. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001. Tables A32 & A33.
3. Estimate based on data from EIA *1998 Natural Gas Annual.* DOE/EIA-0131(98).

TABLE A4
MATERIAL EMBODIED ENERGY FOR PRODUCTION AND TRANSMISSION PIPELINE

	Production	**Transmission**	**Calculation**
Pipeline Embodied Energy	55,933,687	519,122,214	A - See Below
Fraction Applied to Studied Plant	0.192%	0.192%	B - See Page 99
Pipeline Lifetime	30	80	C
Plant Lifetime	40	40	D
Plant Energy Requirement	**143,541**	**499,579**	E = A / C * B * D
I/O Greenhouse Gas Intenstiy (Tonnes CO_2 / GJ)[1]	0.0735	0.0735	F
Plant Emissions (Tonnes CO_2-equiv.)	**10,550**	**36,717**	G = E * F

TABLE A5
PIPELINE MATERIAL EMBODIED ENERGY

Pipe Diameter (inches)	**Embodied Energy (GJ/mile)[2]**	**Production Pipeline (miles)[3]**	**(GJ)[4]**	**Transmission Pipeline (miles)[3]**	**(GJ)[4]**
4	621	13,352	8,292,808	27,983	17,379,873
8	1,824	14,276	26,036,110	71,597	130,575,852
12	2,708	3,070	8,313,618	42,540	115,199,350
16	3,592	3,070	11,028,269	42,540	152,815,465
20	4,477	506	2,262,881	23,043	103,151,674
24	5,361	506	2,709,870	23,043	123,527,313
30	6,687	156	1,039,852	31,746	212,291,546
36	8,014	156	1,246,103	31,746	254,398,960
Total		35,090	**55,933,687**	294,238	**519,122,214**

References and Notes:

1. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001. Tables A32 & A33.
2. Estimate based on mass of pipe per mile times embodied energy for low alloy steel.
3. Estimates based on the Office of Pipeline Safety 1998 Database.
4. Pipeline Energy GJ = (Embodied Energy GJ/mile) * (Pipeline Miles)

TABLE A6: CONSTRUCTION, ENGINEERING, AND ADMINISTRATION ENERGY FOR PRODUCTION AND TRANSMISSION PIPELINE

	Production	Transmission	Calculation
Construction Energy (GJ)	43,345,060	605,749,193	A - See Below
Engineering and Administration Energy (GJ)	39,473,023	567,580,741	B - See Below
Fraction Applied to Studied Plant	0.192%	0.192%	C - See Page 99
Pipeline Lifetime	30	80	D
Plant Lifetime	40	40	E
Plant Energy Requirement	**212,534**	**1,129,159**	F = (A+B) / D * C * E
Construction I/O Emission Intenstiy (Tonnes CO_2-equiv. / GJ)	0.0706	0.0706	G
Eng & Admin I/O Emission Intenstiy (Tonnes CO_2-equiv. / GJ)	0.0679	0.0679	H
Plant Emissions (Tonnes CO_2-equiv.)	**14,734**	**78,259**	I = A * G + B * H

TABLE A7: PIPELINE CONSTRUCTION ENERGY

Pipe Diameter	Constructin	Production Pipeline		Transmission Pipeline	
(inches)	(GJ/mile)[2]	(miles)[3]	(GJ)[4]	(miles)[3]	(GJ)[4]
4	888	13,352	11,854,968	27,983	24,845,362
8	1,110	14,276	15,844,211	71,597	79,461,615
12	2,100	3,070	6,445,586	42,540	89,314,585
16	1,800	3,070	5,525,677	42,540	76,567,673
20	2,496	506	1,261,699	23,043	57,513,574
24	2,677	506	1,353,110	23,043	61,680,447
30	2,882	156	448,172	31,746	91,496,733
36	3,933	156	611,637	31,746	124,869,205
Total		35,090	**43,345,060**	294,238	**605,749,193**

TABLE A8: PIPELINE ENGINEERING & ADMINISTRATION ENERGY

Pipe Diameter	Eng &	Production Pipeline		Transmission Pipeline	
(inches)	(GJ/mile)[2]	(miles)[3]	(GJ)[4]	(miles)[3]	(GJ)[4]
4	837	13,352	11,173,243	27,983	23,416,618
8	1,046	14,276	14,933,082	71,597	74,892,138
12	1,706	3,070	5,236,435	42,540	72,559,731
16	1,555	3,070	4,775,096	42,540	66,167,092
20	2,296	506	1,160,407	23,043	52,896,263
24	2,126	506	1,074,745	23,043	48,991,391
30	2,976	156	462,813	31,746	94,485,798
36	4,226	156	657,203	31,746	134,171,709
Total		35,090	**39,473,023**	294,238	**567,580,741**

References and Notes:

1. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001. Tables A32 & A33.
2. Estimate based on construction cost data from *Oil & Gas Journal Databook* (1998) PennWell Books, p. 176 in conjunction with EIOLCA I/O data.
3. Estimates based on the Office of Pipeline Safety 1998 Database.
4. Pipeline Energy GJ = (Pipeline Energy GJ/mile) * (Pipeline Miles)

TABLE A9: EMISSIONS FROM FUEL COMBUSTION AND METHANE LEAKS

	Fuel-Cycle Methane Leaks		Fuel Combustion	Total
	CH_4 Released[1] (tonnes)	CO_2-equiv. Emissions[2] (Tonnes)	CO_2-equiv. Emissions[3] (Tonnes)	CO_2-equiv. Emissions[4] (Tonnes)
Production	114,099	2,396,077	3,644,468	6,040,544
Processing	46,982	986,620	675,346	1,661,966
Transmission	147,657	3,100,805	1,519,167	4,619,972
Plant Operation	--	--	62,220,103	62,220,103
Total		**6,483,501**	**68,059,084**	**74,542,586**

TABLE A10: LIFE-CYCLE FUEL INPUTS

	Natural Gas Losses[5] (GJ)	Combustion % of Loss[6] (%)	Natural Gas Combustion[7] (GJ)
Production	75,803,437	91.45%	69,322,738
Processing	14,041,802	91.48%	12,846,005
Transmission	34,077,881	84.80%	28,896,624
Operation	1,222,857,000	100.00%	1,222,857,000

Notes:
1. See Table A16
2. (CO_2-equiv. emission tonnes) = (CH_4 leaks tonnes) * 21
3. See Table A11
4. Total Emission = (Methane Leaks CO_2-equiv.) + (Fuel Combustion CO_2-equiv.)
5. See Tables A2 & A12
6. See Table A16 Combustion % = 1- Methane % Loss
7. Natural Gas Combustion GJ = (Input GJ) * (Combustion %)

TABLE A11: GREENHOUSE GAS EMISSIONS FROM FUEL COMBUSTION

	Natural Gas Combustion[1] (GJ)	**Emission Rate[2] (Tonne/GJ)**	**CO_2-equiv. Emissions[3] (Tonnes)**
CO_2	Global Warming Potential[4]: 1		
Production	69,322,738	0.04686	3,248,188
Processing	12,846,005	0.04686	601,913
Transmission	28,896,624	0.04686	1,353,981
Operation	1,222,857,000	0.05057	61,843,733
Subtotal			**67,047,814**
CH_4	Global Warming Potential[4]: 21		
Production	69,322,738	0.00026	376,355
Processing	12,846,005	0.00026	69,741
Transmission	28,896,624	0.00026	156,880
Operation	1,222,857,000	0.00000097	24,892
Subtotal			**627,869**
N_2O	Global Warming Potential[4]: 310		
Production	69,322,738	0.00000093	19,925
Processing	12,846,005	0.00000093	3,692
Transmission	28,896,624	0.00000093	8,306
Operation	1,222,857,000	0.00000093	351,479
Subtotal			**383,401**
TOTAL			**68,059,084**

Notes:
1. See Table A10
2. Emission factors from EPA's AP42, See Tables A34 - A36
3. CO_2-equiv. Emissions = (Combustion GJ) * (Emission Rate Tonne/GJ) * (Global Warming Potential)
4. Intergovernmental Panel on Climate Change (1996). IPCC Second Assessment Climate Change 1995. Cambridge University Press, Volumes 1-3.

TABLE A12

PLANT FUEL LOSSES TO NATURAL GAS PRODUCTION, PROCESSING, & TRANSMISSION

	% Loss	**Natural Gas $m^3 \times 10^6$**	**Energy[3,4] GJ**
Lifetime Plant Deliveries	--	32,210	1,222,857,000
Vent & Flare Loss[1]	1.30%	417	15,848,951
Lease Fuel Loss[2]	4.90%	1,579	59,954,486
Production Losses			**75,803,437**
Processing Plant Losses	1.15%	370	**14,041,802**
Pipeline Fuel Loss	2.79%	898	**34,077,881**
Total Fuel Loss	10.13%	3,264	**123,923,119**

Notes:
1. Vent & Flare Losses are gas released into the air, or burned at the base-site or at gas-processing plants.
2. Lease Fuel is natural gas used in well and field operations.
3. Energy Loss = Lifetime Plant Delivery * % Loss
4. Natural Gas energy content assumed 1020 BTU/ft^3

Supporting data provided in following tables.
Methane density assumed 677 tonne / 10^6 m^3

TABLE A13
PLANT FUEL LOSSES TO PRODUCTION, PROCESSING, & TRANSMISSION (CONTINUED)

NATURAL GAS FUEL-CYCLE ENERGY LOSS ANALYSIS[1]
(Million Cubic Meters)

	Total Losses 1994-1998	% Applicable	Applicable Loss	Loss Basis[5]	% of End Use Nat Gas Losses
Vented & Flared[2]	35,465	76.4%	27,112	2,091,861	1.30%
Lease Fuel[3]	108,292	94.7%	102,560	2,091,861	4.90%
Processing Plant Fuel[4]	60,314	39.8%	24,020	2,091,861	1.15%
Pipeline Fuel	98,658	100.0%	98,658	3,540,262	2.79%
Total					**10.13%**

Notes:
1. Based on U.S. Natural Gas Summary Statistics, See table below.
2. Vent & Flare % Applicable = Dry Production / Gross Withdrawals
3. Lease Fuel % Applicable = Dry Production / (Dry Production + Extraction Loss)
4. Plant Fuel % Applicable based on natural gas processing plant energy requirements (See Table Below)
5. Pipeline losses based on total disposition. All other losses based on U.S. production delivered to end users.

TABLE A14

US NATURAL GAS SUMMARY STATISTICS[1]
1994-1998
(Million Cubic Meters)

	Total
Gross Withdrawals	3,085,981
Vented & Flared	35,465
Repressuring	487,935
Non-hydrocarbon gas removal	71,611
Extractrion Loss	131,845
Dry Production	2,359,125
Lease Fuel	108,292
Processing Plant Fuel	60,314
Pipeline Fuel	98,658
U.S. Production Delivered to End Users	2,091,861
Total Disposition[2]	3,540,262

References and Notes:
1. From EIA *1998 Natural Gas Annual. DOE/EIA-0131(98).*
2. Total disposition is the total natural gas transported including imports, exports, and storage.

TABLE A15
PLANT FUEL LOSSES TO PRODUCTION, PROCESSING, & TRANSMISSION (CONTINUED)

Natural Gas Processing Plant Energy Requirements

Constituent Removed	Processing Energy Required[1] (kJ/m^3)	US (lower 48) Processing Capacity[2] (10^6 m^3 / day)	% of Processing Capacity	Weighted Average Processing Energy (kJ/m^3)	Percentage of weighted Processing Energy
H_2O	11.4	Assume 100%	100.0%	11.392	1.4%
H_2S & CO_2	580.8	1,343	49.6%	288.11	35.8%
N_2	744.6	77	2.8%	21.18	2.6%
Hydrocarbon	744.6	1,762	65.1%	484.53	60.2%
Total		2,707		805.21	100.0%
Percentage of Plant Processing Energy Included in Natural Gas Lifecycle[4]:					**39.8%**

References & Notes:

1. Tannehill C., et al., (March 7-9, 1994) The Cost of Conditioning Your Natural Gas for Market. Proceedings of the 73rd Annual Convention of the Gas Processors Association. New Orleans, LA.
2. Tannehill C., et al., (March 13-15, 1995) U.S. Gas Conditioning and Processing Plant Survey Results. Proceedings of the 74th Annual Convention of the Gas Processors Association, San Antonio, TX.
3. Tannehill C, et al., (March 16-18, 1992) Can You Afford to Extract Your Natural Gas Liquids? Proceedings of the 71st Annual Convention of the Gas Processors Association, Anaheim, California.
4. Hydrocarbon removal is frequently required to meet pipeline specifications. However, because this process is often profitable, it is assumed to have either a break-even or positive energy payback. (See sources 2 & 3) The energy requirements for hydrocarbon removal are therefore excluded from the natural gas lifecycle.

TABLE A16
METHANE EMISSIONS FROM NATURAL GAS PRODUCTION, PROCESSING AND TRANSMISSION

	U.S. 1997 Methane Emission[1] tonnes	**Plant Applicable Methane Emissions[2] tonnes**	**Methane Loss Volume[3,4] $m^3 \times 10^6$**	**Methane % of Natural Gas Losses[4]**
Field Production	1,700,000	**114,099**	2,500	8.55%
Processing	700,000	**46,982**	1,029	8.52%
Transmission	2,200,000	**147,657**	3,235	15.20%
Total	4,600,000	**308,738**	6,765	

References and Notes:

1. U.S. Environmental Protection Agency (1999). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 1997. (USEPA #236-R-99-003).

2. Plant Applicable Methane Emissions = U.S. Methane Emission * 0.00168, where 0.00168 = Lifetime plant delivered fuel / 1997 U.S. fuel delivered to end users

3. Methane density = 680 tonne/ 10^6 m^3 at 60F, 1 atm

4. This calculation estimates the percentage of energy loss associated with methane leaks and the percentange associated with natural gas combustion for the purpose of quantifying greenhouse gas equivalent emissions (e.g., 15% of natural gas losses during transmission are estimated as leaks, and 85% consumed as fuel).

TABLE A17: ENERGY REQUIREMENTS FOR COMPRESSOR STATIONS AND MISCELLANEOUS EQUIPMENT

Equipment Type	Book Value $[1]	Energy Intensity[2] (GJ/97$)	Plant Energy[3] GJ
Compressor Station	10,508,211,129	0.0103	123,417
Structures and Improvements	1,785,797,504	0.0071	14,442
Measuring and Regulating	1,585,101,183	0.0067	12,090
Communication	466,465,896	0.0052	2,796
Other	353,084,421	0.0103	4,155
Total			**156,900**

TABLE A18: GREENHOUSE GAS EMISSIONS FROM COMPRESSOR STATIONS AND MISCELLANEOUS EQUIPMENT

Equipment Type	Plant Energy GJ	CO_2-equiv. Intensity[2] (tonne/GJ)	Plant Emissions[4] tonne CO_2
Compressor Station	123,417	0.0718	8,862
Structures and Improvements	14,442	0.0716	1,035
Measuring and Regulating	12,090	0.0724	875
Communication	2,796	0.0704	197
Other	4,155	0.0725	301
Total			**11,270**

References & Notes:

1. FERC (1999) *1998 Form 2,* pg 204. Gas Plant in Service (Accts 101, 102, 103, and 106) - End of Year Balance.

2. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001. Tables A32 & A33.

3. Plant Energy = Book Value * Energy Intensity / 0.974 * 0.0011, where 0.974 is the fraction of U.S. gas equipment accounted for by FERC, and 0.0011 is the fraction of pipeline disposition delivered to the studied plant.

4. Plant Emissions = Plant Energy * CO_2 Intensity

TABLE A19: ENERGY REQUIREMENTS FOR TRANSMISSION SYSTEM OPERATION AND MAINTENANCE

Equipment Type	Book Value $[1]	Energy Intensity[2] (GJ/97$)	Plant Energy[3] GJ
Operation, Supervision and Engineering	$213,480,538	0.0036	34,725
System Control and Load Dispatching	$40,075,679	0.0036	6,519
Communication System Expenses	$46,131,550	0.0036	7,504
Compressor Station Labor and Expenses	$326,963,856	0.0071	105,811
Mains Expenses	$202,514,040	0.0071	65,537
Measuring and Regulating Station Expenses	$72,611,345	0.0071	23,498
Transmission and Compression of Gas by Others	$285,793,821	0.0045	58,957
Other Expenses	$82,282,683	0.0052	19,605
Maintenance Supervision and Engineering	$17,948,164	0.0028	2,325
Maintenance of Structures and Improvements	$23,961,495	0.0071	7,754
Maintenance of Mains	$78,572,815	0.0071	25,428
Maintenance of Compressor Station Equipment	$218,263,451	0.0071	70,634
Maintenance of Measuring and Regulating Station Equipment	$17,985,141	0.0071	5,820
Maintenance of Communication Equipment	$10,233,590	0.0071	3,312
Maintenance of Other Equipment	$11,472,495	0.0071	3,713
Total Operation and Maintenance[4]			**441,141**

References & Notes:

1. FERC (1999) *1998 Form 2,* pg 317. Transmission Expenses.

2. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001. Tables A32 & A33.

3. Plant Energy = Book Value * Energy Intensity / 0.974 * 0.0011*(40years), where 0.974 is the fraction of U.S. gas equipment accounted for by FERC, and 0.0011 is the fraction of pipeline disposition delivered to the studied plant.

4. Total excludes direct fuel losses from leaks and consumption included in Table A13.

TABLE A20: GREENHOUSE GAS EMISSIONS FROM TRANSMISSION SYSTEM OPERATION AND MAINTENANCE

Equipment Type	**Plant Energy[1] GJ**	**CO_2-equiv. Intensity[2] (tonne/GJ)**	**Plant Emissions[3] tonnes CO_2**
OPERATION			
Operation, Supervision and Engineering	34,725	0.0679	2,358
System Control and Load Dispatching	6,519	0.0679	443
Communication System Expenses	7,504	0.0679	510
Compressor Station Labor and Expenses	105,811	0.0708	7,488
Mains Expenses	65,537	0.0708	4,638
Measuring and Regulating Station Expenses	23,498	0.0708	1,663
Transmission and Compression of Gas by Others	58,957	0.0701	4,134
Other Expenses	19,605	0.0659	1,292
MAINTENANCE			
Supervision and Engineering	2,325	0.0659	153
Structures and Improvements	7,754	0.0708	549
Mains	25,428	0.0708	1,799
Compressor Station Equipment	70,634	0.0708	4,998
Measuring and Regulating Station Equipment	5,820	0.0708	412
Communication Equipment	3,312	0.0708	234
Other Equipment	3,713	0.0708	263
Total Operation and Maintenance			**30,934**

References & Notes:

1. From previous page.

2. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001. Tables A32 & A33.

3. Plant Emissions = Plant Energy * CO_2 Intensity

TABLE A21: INVENTORY OF PLANT MATERIALS

	Quantity[1,2]	Units	Density (kg/m^3)	Tonnes
Structural Steel	700	tons	--	635.0
Concrete	14,000	CY	2,750	29,439.3
Rebar	800	tons	--	725.8
Paneling				
- Aluminum	1		2,700	1.8
- Steel	2		7,900	15.5
Pipe:				
- A335 Alloy	6,000	LF	7,900	31.7
- A106 Carbon Steel	25,500	LF	7,900	134.5
- Copper	5,000	LF	9,000	2.2
- Concrete	1,200	LF	2,750	220.4
- HDPE	13,840	LF	944	8.7
- Ductile Iron	13,840	LF	7,900	73.0
- PVC	6,920	LF	1,400	6.5

TABLE A22: ALLOYING COMPONENTS

	Structural Steel	Rebar	Pipe - A335	Pipe - A106 Carbon Steel	Total
Mass (tonnes)	635	725.8	31.7	134.5	
ASTM Spec	A572	A36	A335	A106	
Manganese	1.350%	1.000%	0.455%	0.600%	
Silicon	0.300%	0.225%	0.500%	0.100%	
Copper		0.200%			
Chromium			1.020%		
Molybedenum			0.545%		
Vanadium	0.080%				
Manganese (tonnes)	8.57	7.26	0.14	0.81	**16.782**
Silicon (tonnes)	1.91	1.63	0.16	0.13	**3.831**
Copper (tonnes)	0.00	1.45	0.00	0.00	**1.452**
Chromium (tonnes)	0.00	0.00	0.32	0.00	**0.323**
Molybedenum (tonnes)	0.00	0.00	0.17	0.00	**0.172**
Vanadium (tonnes)	0.51	0.00	0.00	0.00	**0.508**

References and Notes:

1. Estimates based on data from Sherman, M. (2000) Vice President, Project Development, Aquila Energy, Personal Communications.

2. Estimates based on data from Morford, K. (2000) Black and Veatch Corporation, Personal Communications.

TABLE A23
INVENTORY OF MATERIAL EMBODIED ENERGY AND CO_2 EMISSIONS

Element or Alloy	Material Embodied Energy		Material Embodied Emissions	
	GJ/Tonne	Reference	kg CO_2/Tonne	Reference
Aluminum	201.4	[2]	13,288	[5]
Chromium	82.9	[1]	5,393	[5]
Concrete	1.4	[2]	520	[5]
Copper	131.0	[2]	7,446	[5]
Iron	23.5	[2]	1,688	[5]
Carbon Steel	34.4	[2]	2,471	[5]
High Alloyed Steels	53.1	[4]	3,275	[5]
Manganese	51.5	[3]	5,502	[5]
Molybdenum	378.0	[1]	9,410	[5]
Plastic	54.0	[5]	6,388	[5]
Silicon	158.6	[3]	159	[5]
Vanadium	3,711.2	[1]	228,379	[5]

References and Notes:
Data compiled or calculated by Scott White (1999), University of Wisconsin.

1. Penner, P. and Speck J. (1976) Stockpile Optimization: Energy and Versatility Considerations for Strategic and Critical Materials. University of Illinois at Urbana-Champaign. CAC Document No 217.

2. Bureau of Mines (1975) Energy Use Patterns in Metallurgical and Nonmetallic Mineral Processing (Phase 4), PB-245 759, Battelle Columbus Laboratories.

3. Bureau of Mines (1975) Energy Use Patterns in Metallurgical and Nonmetallic Mineral Processing (Phase 5), PB-246 357, Battelle Columbus Laboratories.

4. Bunde, R. (1985) The Potential Net Energy Gain from DT Fusion Power Plants, Nuclear Engineering and Design/Fusion, 3: pp. 1-36.

5. White, S. (1999) Energy Requirements and CO_2 emissions in the construction and manufacture of Power Plant Materials – Working Draft, University of Wisconsin-Madison.

TABLE A24: ENERGY EMBODIED IN PLANT MATERIAL

Element or Alloy	Mass[1] (Tonnes)	Energy Intensity[2] (GJ/Tonne)	Energy Totals[3] GJ
Aluminum	1.8	201.4	355
Chromium (High C Fe Cr)	0.32	82.9	27
Concrete	29,660	1.4	40,876
Copper (Refined)	4	130.6	479
Iron	73	23.5	1,718
Carbon Steel (castings)	134	34.4	4,600
High Alloyed Steels	1,386	53.1	73,594
Manganese	17	51.5	864
Molybdenum (FeMo)	0.17	378.0	65
Plastic	15	54.0	820
Silicon	3.8	158.6	608
Vanadium (FeV)	0.51	3,711.2	1,885
Total			**125,891**

TABLE A25: EMISSIONS EMBODIED IN PLANT MATERIAL

Element or Alloy	Mass[1] (Tonnes)	CO_2 Intensity[2] (kg/Tonne)	CO_2 Emission[4] (Tonnes)
Aluminum	1.8	13,287.9	23.4
Chromium (High C Fe Cr)	0.32	5,393.4	1.7
Concrete	29,660	519.9	15,419.2
Copper (Refined)	4	7,446.4	27.3
Iron	73	1,688.3	123.3
Carbon Steel (castings)	134	2,471.2	330.1
High Alloyed Steels	1,386	3,274.6	4,537.8
Manganese	17	3,502.2	58.8
Molybdenum (FeMo)	0.17	9,410.1	1.6
Plastic	15	6,387.6	97.0
Silicon	3.8	158.6	0.6
Vanadium (FeV)	0.51	228,379.0	116.0
Total			**20,737**

References and Notes:

1. Material Inventory from Table A21.
2. Energy and CO_2 Intensity references from Table A23.
3. Energy = Mass * Energy Intensity
4. Emission = Mass * CO_2 Intensity / 1000

TABLE A 26

ENERGY AND EMISSIONS ASSOCIATED WITH PLANT EQUIPMENT

Description	**Cost[1] (1999$)**	**Energy Intensity[2] (GJ/99$)**	**Energy[3] (GJ)**	**CO_2-equiv. Intensity[2] (tonne/GJ)**	**CO_2-equiv. Emission[4] (tonnes)**
	Proprietary[5]				
Combustion Turbines	[redacted]	0.008799	570,073	0.072400	41,273
Transformers	[redacted]	0.016821	65,158	0.072524	4,725
Steam Generator	[redacted]	0.012112	35,187	0.072928	2,566
Pumps	[redacted]	0.009963	38,067	0.071316	2,715
Condensers	[redacted]	0.011140	16,791	0.072223	1,213
Electrical Equipment	[redacted]	0.012056	83,048	0.070966	5,894
Noise Attenuation	[redacted]	0.006809	1,780	0.070763	126
Road upgrades	[redacted]	0.009275	4,638	0.064805	301
Pipeline & Header Interconnect	[redacted]	0.006176	42,064	0.069562	2,926
Total			**856,804**		**61,738**

Reference and Notes:

1. Based on construction budget from Sherman, M. (2000) Vice President, Project Development, Aquila Energy, Personal Communications.
2. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001. Tables A32 & A33.
3. Energy = Cost * Energy Intensity
4. Emissions = Plant Energy * CO_2 Intensity
5. Itemized cost data is proprietary and could not be released at the time of this publication.

TABLE A 27: ENERGY AND EMISSIONS ASSOCIATED WITH PLANT CONSTRUCTION

Description	**Cost[1] (1999$)**	**Energy Intensity[2] (GJ/99$)**	**Energy[3] (GJ)**	**CO_2-equiv. Intensity[2] (tonne/GJ)**	**CO_2-equiv. Emission[4] (Tonnes)**
	Proprietary[5]				
Engr. & Administration	[redacted]	0.003422	95,880	0.067916	6,512
Plant Construction & Equipment Assembly	[redacted]	0.006809	498,304	0.070763	35,262
Facility Testing & Completion	[redacted]	0.004585	34,300	0.070005	2,401
Site Assessment & Permitting	[redacted]	0.002362	772	0.069246	53
Business Administration	[redacted]	0.005013	66,049	0.065920	4,354
Total			**695,305**		**48,582**

Reference and Notes:
1. Based on construction budget from Sherman, M. (2000) Vice President, Project Development, Aquila Energy, Personal Communications.
2.. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001. Tables A32 & A33.
3. Energy = Cost * Energy Intensity
4. Emissions = Plant Energy * CO_2 Intensity
5. Itemized cost data is proprietary and could not be released at the time of this publication.

TABLE A28: ENERGY AND EMISSIONS ASSOCIATED WITH PLANT CONSTRUCTION

Description	Cost[1] (1999$)	Energy Intensity[2] (GJ/99$)	Energy[3] (GJ)	CO_2-equiv. Intensity[2] (tonne/GJ)	CO_2-equiv. Emission[4] (Tonnes)
Water Supply & Treatment	**Proprietary[5]** [redacted]	0.016268	625,561	0.066307	41,479
Staff Labor	[redacted]	0.005013	519,967	0.065920	34,276
Major Maintenance	[redacted]	0.006809	1,710,199	0.070763	121,020
Routine Maintenance	[redacted]	0.006809	185,687	0.070763	13,140
Materials & Supplies	[redacted]	0.009903	247,122	0.072469	17,909
Contract Services	[redacted]	0.002362	20,289	0.069246	1,405
Administrative Overhead	[redacted]	0.005013	130,288	0.065920	8,589
Other Expenses	[redacted]	0.005013	13,671	0.065920	901
Startup Costs	[redacted]	0.009543	176,508	0.070250	12,400
Maintenance Subtotal			***3,629,293***		***251,118***
Replacement Parts	[redacted]	0.008799	1,713,677	0.072400	124,070
Repair Parts	[redacted]	0.008799	661,200	0.072400	47,871
Parts Subtotal			***2,374,877***		***171,941***
TOTAL	[redacted]		**6,004,170**		**423,059**

Reference and Notes:

1. Based on construction budget from Sherman, M. (2000) Vice President, Project Development, Aquila Energy, Personal Communications.
2. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001. Tables A32 & A33.
3. Energy = Annual Cost * Energy Intensity * 40 years
4. Emissions = Plant Energy * CO_2 Intensity
5. Itemized cost data is proprietary and could not be released at the time of this publication.

TABLE A29
ENERGY AND EMISSIONS ASSOCIATED WITH PLANT DECOMMISSIONING

Description	**Cost[1] (1999$)**	**Energy Intensity[2] (GJ/99$)**	**Energy[3] (GJ)**	**CO_2-equiv. Intensity[2] (tonne/GJ)**	**CO_2-equiv. Emission[4] (Tonnes)**
Dismantling	$6,034,821	0.006955	41,970	0.070763	2,970
Building Demolition					
General Services Bldg	$43,680	0.006955	304	0.070763	21
Water Treatment Bldg.	$38,640	0.006955	269	0.070763	19
Electrical Equip. Bldg	$24,696	0.006955	172	0.070763	12
Total			**42,714**		**3,023**

Reference and Notes:
1. Decommissioning estimated as 10% of equipment costs. Demolition cost estimated based on data for low-rise steel frame demolition from Frank R. Walker Company, (1999) The Building Estimator's Reference Book (26th ed.) Chicago, IL.

2. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001. Tables A32 & A33.
3. Energy = Cost * Energy Intensity
4. Emissions = Energy * CO_2 Intensity

TABLE A30: ENERGY ASSOCIATED WITH LAND RECLAMATION

Description	Acres	Plant Fraction[1]	Plant Applied Acres	Seeding Cost[2] ($/acre)	Lifetime (years)	Cost[3] (1999$)
Transmission Pipeline	1,047,134	0.00077	806	1500	80	$604,628
Gathering Pipeline	104,818	0.00192	202	1500	40	$302,617
Plant	97	1.0	97	1500	40	$145,500

TABLE A31: GREENHOUSE GASES ASSOCIATED WITH LAND RECLAMATION

Description	Cost (1999$)	Energy Intensity[4] (GJ/99$)	Energy[5] (GJ)	CO_2-equiv. Intensity[4] (tonne/GJ)	CO_2-equiv. Emission[6] (Tonnes)
Transmission Pipeline	$604,628	0.015689	9,486	0.056771	539
Gathering Pipeline	$302,617	0.015689	4,748	0.056771	270
Plant	$145,500	0.015689	2,283	0.056771	130
TOTAL			**16,517**		**938**

Reference and Notes:

1. Estimated based on plant's prorated use of U.S. pipeline.
2. Frank R. Walker Co. (1999) The Building Estimator's Reference Book (26th ed.) Chicago, IL.
3. Cost = Plant Applied Acres * Seeding Cost * Plant Lifetime / Pipeline Lifetime
4. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001. Tables A32 & A33.
5. Energy = Cost * Energy Intensity
6. Emissions = Energy * CO_2 Intensity

TABLE A32
INPUT/OUTPUT ENERGY INTENSITY & GREENHOUSE GAS INTENSITY

Item	Energy Intensity[1] (TJ/Mil 92$)	CO_2-equiv. Intensity[1] (tonne/Mil 92$)	CO_2-equiv. Intensity[2] (tonne/GJ)
Petroleum, Nat Gas, and solid mineral exploration	9.998	706.1	0.0706
Crude petroleum & nat gas mining	151.383	6930.9	0.0458
Petroleum & nat gas well drilling	17.780	1237.1	0.0696
Maintenance & repair of petroleum & nat gas wells	9.515	671.9	0.0706
Other repair & maintenance construction	8.085	572.1	0.0708
Oil & gas field machinery & equipment	17.230	1277.2	0.0741
Pipe, valves, and pipe fittings	15.000	1102.4	0.0735
Pumps & compressors	11.831	843.7	0.0713
Turbines & turbine generator sets	10.449	756.5	0.0724
Motors & generators	14.383	1048.9	0.0729
General industrial machinery	11.759	852.2	0.0725
Refrigeration & heating equipment	13.229	955.4	0.0722
Ready mixed concrete	30.411	2201.7	0.0724
Other new construction	8.082	579.0	0.0716
Engineering, architectural & surveying services	2.804	194.2	0.0692
Other business services	5.953	392.4	0.0659
Public building & related furniture	15.118	1085.8	0.0718
Industrial Inorganic & Organic chemicals	42.490	2503.6	0.0589
Industrial trucks & tractors	16.366	1224.4	0.0748
Power, distribution, & specialty transformers	19.974	1448.6	0.0725
Electrical industrial apparatus	14.316	1016.0	0.0710
Electronic computers	6.563	459.6	0.0700
Communication Equipment	5.990	421.4	0.0704
Mechanical Measuring Device	7.622	551.5	0.0724
Water supply & Sewerage	19.317	1280.9	0.0663
Agriculture, forestry, & fishery services	18.239	1035.4	0.0568
Maintenance & repair of highways & streets	11.014	713.8	0.0648

Reference and Notes:

1. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001.
2. (CO2 Intensity tonne/GJ) = (CO2 Intensity tonne Mil$) / (Energy Intensity TJ/$) / 1000

1996 CPI Adjustment, multiply 1992 intensity by: 0.8942
1997 CPI Adjustment, multiply 1992 intensity by: 0.8741
1998 CPI Adjustment, multiply 1992 intensity by: 0.8602
1999 CPI Adjustment, multiply 1992 intensity by: 0.8421

TABLE A33
INPUT/OUTPUT ENERGY INTENSITY & GREENHOUSE GAS INTENSITY (CONTINUED)

Item	**Energy Intensity[1] (TJ/Mil 92$)**	**CO_2-equiv. Intensity[1] (tonne/Mil 92$)**	**CO_2-equiv. Intensity[2] (tonne/GJ)**
HYBRIDS			
Engineering & Administration			
Engineering, architect. & surveying services (60%)	2.804	194.2	0.0692
Other business services(40%)	5.953	392.4	0.0659
		273.5	**0.0679**
Compressor Station			
Pumps & compressors (60%)	11.831	843.7	0.0713
Pipe, valves, and pipe fittings (15%)	15.000	1102.4	0.0735
Other new construction (15%)	8.082	579.0	0.0716
General industrial machinery (10%)	11.759	852.2	0.0725
		843.7	**0.0718**
Installed Pipeline			
Pipe, valves, and pipe fittings (17%)	15.000	1102.4	0.0735
Maint. & repair of petroleum & nat gas wells (26%)	9.515	671.9	0.0706
Engineering, architectural & surveying services (34%)	2.804	194.2	0.0692
Other business services (23%)	5.953	392.4	0.0659
		517.5	**0.0696**

Reference and Notes:

1. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001.
2. (CO2 Intensity tonne/GJ) = (CO2 Intensity tonne Mil$) / (Energy Intensity TJ/$) / 1000

1996 CPI Adjustment, multiply 1992 intensity by: 0.8942
1997 CPI Adjustment, multiply 1992 intensity by: 0.8741
1998 CPI Adjustment, multiply 1992 intensity by: 0.8602
1999 CPI Adjustment, multiply 1992 intensity by: 0.8421

EPA GREENHOUSE GAS EMISSION FACTORS FOR NATURAL GAS COMBUSTION

TABLE A34: CARBON DIOXIDE EMISSION FACTORS

Source	Emission Rate (tonne/GJ)	Reference
Natural Gas Production	0.04686	[1]
Natural Gas Processing	0.04686	[1]
Natural Gas Transmission	0.04686	[1]
Natural Gas Power Generation	0.05057	[2]

TABLE A35: METHANE EMISSION FACTORS

Source	Emission Rate (tonne/GJ)	Reference
Natural Gas Production	0.00026	[3]
Natural Gas Processing	0.00026	[3]
Natural Gas Transmission	0.00026	[3]
Natural Gas Power Generation	0.00000097	[2]

TABLE A36: NITROUS OXIDE EMISSION FACTORS

Source	Emission Rate (tonne/GJ)	Reference
Natural Gas Power Generation	0.00000093	[2]

Reference and Notes:

From U.S. Environmental Protection Agency (1996). 5th Edition AP-42.:

1. AP-42 3.2 for Heavy-duty Natural Gas-fired Pipeline Compressor Engines.
2. AP-42 1.4 for Natural Gas Combustion, assumes 1020 BTU/scf.
3. AP-42 3.2 based on weighted average of gas turbine, 2-cycle and 4-cycle engines.

APPENDIX B

LIFE-CYCLE ASSESSMENT FOR
8 KW BUILDING-INTEGRATED PHOTOVOLTAIC SYSTEM

DATA AND CALCULATIONS

TABLE B1: ENERGY SUMMARY

Life-Cycle Component	Energy (GJ)	Reference Tables
PV Modules		
Materials and Manufacturing	123.0	B3 - B4
Engineering & Administration	39.3	B3 - B4
Finished Product Transport	7.2	B5
Balance of System		
Inverters	4.0	B13
Wiring	2.9	B14
Installation	12.9	B15
Operation and Maintenance	11.0	B16
Decommissioning and Disposal	4.3	B17 - B19
TOTAL LIFE-CYCLE ENERGY	**204.7**	
TOTAL LIFE-CYCLE AC ELECTRICAL OUTPUT	**1,165**	B20

TABLE B2: GREENHOUSE GAS SUMMARY

Life-Cycle Component	Greenhouse Gas Emissions (kg CO_2-equiv.)	Reference Pages
PV Modules		
Materials and Manufacturing	7,315	B6 - B12
Engineering & Administration	2,221	B6 - B12
Finished Product Transport	534	B6 - B12
Balance of System		
Inverters	290	B13
Wiring	179	B14
Installation	897	B15
Operation and Maintenance	776	B16
Decommissioning and Disposal	297	B17 - B19
TOTAL LIFE-CYCLE EMISSION	**12,508**	

Additional Information	Reference Pages
Opportunity losses due to slope and orientation	B21 - B24
Input/output energy and greenhouse gas intensity	B25

TABLE B3: ENERGY INPUT REQUIREMENTS FOR PV MODULES

	Unit Energy GJ/m^2	Module Area m^2	Total GJ
Materials & Manufacturing[1]	0.782	157	**123**
Engineering & Administration[2]	0.250	157	**39**
Transportation to Site[3]	0.046	157	**7**
		Total Energy	**170**

TABLE B4: MODULE MATERIAL & MANUFACTURING ENERGY[1]

	Energy Per Module Area (GJ/m^2)			
Activity	**Material**	**Manufacturing**	**Material Transport**	**Total**
Encapsulation	0.2119	0.1372	0.0188	0.3680
Substrate	0.0256	0.0564	0.0093	0.0913
Deposition Materials	0.0188	0.0925	0.0002	0.1116
Busbar	0.0051	0.0000	0.0002	0.0054
Back Reflector	0.0007	0.0740	--	0.0747
Grid	--	0.0342	--	0.0342
Conductive Oxide	--	0.0969	--	0.0969
Total	0.262	0.491	0.029	**0.782**

References and Notes:

1. Keoleian, G. and Lewis, G. (1997) Application of Life-cycle Energy Analysis to Photovoltaic Module Design. Progress in Photovoltaics: Research and Applications. 5: pp. 287-300.
2. Alsema, E. (2000) *Energy pay-back time and CO_2 emissions of PV systems.* Progress in Photovoltaics: Research and Applications. 8: pp. 17-25.
3. See Table B5.

TABLE B5: TRANSPORTATION TO SITE ENERGY

Distance	miles	928
Energy Intensity[1]	BTU/ton Mile	4,359
Mass	tons	1.69
Transport Energy[2]	GJ	7.22
Area	m^2	157
Unit Transport Energy[3]	GJ/m^2	**0.046**

References and Notes:

1. Energy Information Administration (1995) *Measuring Energy Efficiency in the United States' Economy: A Beginning*. DOE/EIA-0555(95)/2.
2. Transport Energy GJ = (Distance) * (Energy Intensity) * (Mass) * (1.055E-6 GJ/BTU)
3. Unit Transport Energy GJ/m^2 = (Transport Energy GJ) / (Area m^2)

GREENHOUSE GAS EMISSIONS FOR PV MODULES (Page 1 of 3)

TABLE B6: SUMMARY

Component	Unit Emission kg CO_2/m^2	Module Area m^2	Total kg CO_2-Equiv	Reference Page
Materials & Manufacturing				
Material	16.7			See Table B7
Manufacturing	27.7			See Table B8
Intermediate Transport	2.1			See Table B9
Subtotal	***46.5***	***157***	***7,315***	
Engineering & Administration	14.121	157	2,221	See Table B10
Transportation to Site	3.394	157	534	See Table B11
Total			**10,070**	

TABLE B7: MATERIAL EMBODIED EMISSIONS

Activity	Material	Unit Energy[1] MJ/m^2	Emission Factor[2,3] kg CO_2/MJ	Unit Emission[4] kg CO_2/m^2
Encapsulation	Various	211.94	0.064	13.504
Substrate	Stainless Steel	25.64	0.062	1.579
Deposition Materials	Various	18.80	0.064	1.198
Busbar	Various	5.13	0.064	0.327
Back Reflector	Various	0.73	0.064	0.047
Grid	Various	--	--	--
Conductive Oxide	Various	--	--	--
Total				**16.7**

References and Notes:

1. Keoleian G. and Lewis G. (1997) Application of Life-cycle Energy Analysis to Photovoltaic Module Design. Progress in Photovoltaics: Research and Applications. 5: pp. 287-300.

2. See estimate included on Page 138

3. Stainless steel emission factor from White, S. (1999) Energy Requirements and CO2 Emissions in the Construction and Manufacture of Power Plants - Working Draft, University of Wisconsin - Madison.

4. Unit Emission = Unit Energy * Emission Factor

GREENHOUSE GAS EMISSIONS FOR PV MODULES (Page 2 of 3)

TABLE B8: MANUFACTURING EMISSIONS

Activity	Unit Energy[1] MJ/m^2	Emission Factor[2] kg CO_2/MJ	Unit Emission[3] kg CO_2/m^2
Encapsulation	137.23	0.056	7.75
Substrate	56.40	0.056	3.19
Deposition Materials	92.54	0.056	5.23
Back Reflector	73.99	0.056	4.18
Grid	34.18	0.056	1.93
Conductive Oxide	96.94	0.056	5.48
Total			**27.75**

TABLE B9: INTERMEDIATE TRANSPORT EMISSIONS

Activity	Unit Energy[1] MJ/m^2	Emission Factor[2] kg CO_2/MJ	Unit Emission[3] kg CO_2/m^2
Encapsulation	18.80	0.074	1.39
Substrate	9.28	0.074	0.68
Deposition Materials	0.24	0.074	0.02
Busbar	0.24	0.074	0.02
Back Reflector	--	--	--
Grid	--	--	--
Conductive Oxide	--	--	--
Total			**2.11**

References and Notes:

1. Keoleian G. and Lewis G. (1997) Application of Life-cycle Energy Analysis to Photovoltaic Module Design. Progress in Photovoltaics: Research and Applications. 5: pp. 287-300.
2. See Table B12
3. Unit Emission = Unit Energy * Emission Factor

GREENHOUSE GAS EMISSIONS FOR PV MODULES (Page 3 of 3)

TABLE B10: ENGINEERING & ADMINISTRATION EMISSIONS

Activity	**Unit Energy[1] MJ/m²**	**Emission Factor[2] kg CO_2/MJ**	**Unit Emission[3] kg CO_2/m²**
Engineering & Administration	250	0.056	**14.12**

TABLE B11: TRANSPORTATION TO SITE EMISSIONS

Activity	**Unit Energy[4] MJ/m²**	**Emission Factor[2] kg CO_2/MJ**	**Unit Emission[3] kg CO_2/m²**
Transportation to Site	46	0.074	**3.39**

TABLE B12: U.S. EMISSION FACTORS*

Energy Source	**Emission Rate (kg CO_2/MJ)**
U.S. Primary Energy	**0.064**
U.S. Electricity	**0.056**
U.S. Diesel Fuel	**0.074**

*Estimates based on data from references 5,6,7

References and Notes:

1. Alsema E. (2000) Energy pay-back time and CO2 emissions of PV systems. Progress in Photovoltaics: Research and Applications. 8: pp. 17-25.
2. See Table B12
3. Unit Emission = Unit Energy * Emission Factor
4. See Table B13
5. U.S. Environmental Protection Agency (1999) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–1997. USEPA #236-R-99-003.
6. Organisation for Economic Cooperation and Development (1991) Greenhouse Gas Emissions: The Energy Dimension. OECD611990091P1.
7. Energy Information Administration (1999) Annual Energy Review 1998. DOE/EIA-0384(98).

BALANCE OF SYSTEM ENERGY REQUIREMENTS AND CO_2-Equiv. EMISSIONS

TABLE B13: INVERTERS

Inverter Capacity[1]	4000	W
Energy Intensity[2]	0.001	GJ/W
Number of System Inverters[3]	3	
Energy Required[4]	**4.0**	**GJ**
CO_2 Intensity[5]	72.5	kg CO_2/GJ
CO_2-equiv. Emissions[6]	**290**	**kg**

TABLE B14: WIRING

AC Wiring[3]	100	feet
DC Wiring[3]	400	feet
Copper Required[7]	24	kg
Energy Intensity[8]	0.12	GJ/kg
Energy Required[9]	**2.9**	**GJ**
CO_2 Intensity[8]	62.4	kg CO_2/GJ
CO_2-equiv. Emissions[6]	**179**	**kg**

References and Notes:

1. Trace Engineering. (April 9, 2001) Via: http://www.traceengineering.com.
2. Alsema, E. (2000) *Energy pay-back time and CO_2 emissions of PV systems.* Progress in Photovoltaics: Research and Applications. 8: pp. 17-25.
3. Burdick, J. (2001) President, Burdick Technologies Unlimited, LLC. Personal Communications.
4. Energy Required = Inverter Capacity * Energy Intenstiy * 3 Inverters
5. Carnegie Mellon University (2001) *Energy Input Output Life Cycle Analysis Database* . Via: http://www.eiolca.net/. (See Table B25).
6. Emissions = Energy Required + CO_2 Intensity
7. Based on 0.009 kg copper per foot for AC wire and 0.0575 kg copper per foot for DC wire.
8. White, S. (1999) *Energy Requirements and CO2 Emissions in the Construction and Manufacture of Power Plants - Working Draft* , University of Wisconsin - Madison.
9. Energy Required = Copper Required * Energy Intenstiy

INSTALLATION, OPERATION & MAINTENANCE
ENERGY REQUIREMENTS AND CO_2-Equiv. EMISSIONS

TABLE B15: INSTALLATION

	Cost[1,2] ($)	**Energy Intensity[3] GJ/$**	**Energy Required[4] GJ**	**CO_2-Equiv. Intensity[3] kg CO_2/GJ**	**CO_2-equiv. Emission[5] kg**
Installation (excludes roofing)	5667	0.00228	**12.9**	69.25	**897**

TABLE B16: OPERATION & MAINTENANCE

	Cost[1,2] ($)	**Energy Intensity[3] GJ/$**	**Energy Required[4] GJ**	**CO_2-Equiv. Intensity[3] kg CO_2/GJ**	**CO_2-Equiv. Emission[5] kg**
Year 1 - System Optimization	1000	0.00228	2.3	69.25	158
Year 15 - Inverter Replacement[6]			4.0		290
Miscellaneous	1500	0.00315	4.7	69.55	328
TOTAL			**11.0**		**776**

References and Notes:

1. Burdick, J. (2001) President, Burdick Technologies Unlimited, LLC, Personal Communications.
2. Bertsche, G. (June 14, 2001) Regional Sales Manager, Uni-Solar Corporation, Personal Communications.
3. Carnegie Mellon University (2001) *Energy Input Output Life Cycle Analysis Database* . Via: http://www.eiolca.net/. (See Table B25).
4. Energy Required = Cost * Energy Intensity
5. CO_2-equiv. Emission = Cost * CO_2-equiv. Intensity
6. Energy requirements and emissions estimated in Table B13.

DECOMMISSIONING AND DISPOSAL (PAGE 1 OF 2)
ENERGY REQUIREMENTS AND CO_2-Equiv. EMISSIONS

TABLE B17: SUMMARY

Item	Energy GJ	CO_2-Equiv. Emission (kg)
Decommissioning[1]	2.59	179.32
Transportation	0.257	18.94
Disposal[2]	1.455	98.39
Total Decom. and Disposal	**4.30**	**296.7**

TABLE B18: TRANSPORTATION

Component	Mass kg	Transport Intensity[3] GJ/kg	Transport Energy[4] GJ	Emission Factor[5] kg CO_2/GJ	Transport Emission[6] kg CO_2
Modules	1,535	0.00015	0.233	73.80	17.23
Inverter	48	0.00015	0.007	73.80	0.54
Wiring	24	0.00015	0.004	73.80	0.27
Manufacturing Solid Waste[7]	77	0.00015	0.012	73.80	0.86
Manufacturing Chemical Waste[8]	4	0.00015	0.001	73.80	0.05
Total			**0.257**		**18.94**

References and Notes:

1. Decommissioning energy and emissions estimated as 20% of installation energy and emissions.
2. See Table B19
3. Energy Information Administration (1995) *Measuring Energy Efficiency in the United States' Economy: A Beginning.* DOE/EIA-0555(95)/2. Assumes a 30 mile transport distance.
4. Energy = Mass * Energy Intensity
5. Organisation for Economic Cooperation and Development (1991) Greenhouse Gas Emissions: The Energy Dimension. OECD611990091P1.
6. Emission = Mass * Emission Factor
7. Fthenakis, V. (2000) *End-of-life management and recycling of PV modules.* Energy Policy. 28: pp. 1051-1058.
8. Dones, R. and Frischknecht, R. (1998) *Life-cycle Assessment of Photovoltaic Systems: Results of Swiss Studies on Energy Chains.* Progress in Photovoltaics: Research and Applications. 6: pp. 117-125.

DECOMMISSIONING AND DISPOSAL (PAGE 2 OF 2)
ENERGY REQUIREMENTS AND CO_2-Equiv. EMISSIONS

TABLE B19: DISPOSAL

Component	Mass kg	Disposal Intensity[1] GJ/kg	Disposal Energy[4] GJ	Emission Factor[1] kg CO_2/GJ	Disposal Emission[5] kg CO_2
Modules	1535	0.00072	1.11	70.763	78.61
Inverter	48	0.00072	0.03	70.763	2.46
Wiring	24	0.00072	0.02	70.763	1.23
Manufacturing Solid Waste[2]	77	0.00072	0.06	70.763	3.93
Manufacturing Chemical Waste[6]	4	0.05804	0.24	51.397	12.17
			1.455		**98.39**

References and Notes:

1. Estimates based on data from references 2 and 3.
2. Fthenakis, V. (2000) End-of-life management and recycling of PV modules.Energy Policy. 28: pp. 1051-1058.
3. Carnegie Mellon University (2001) *Energy Input Output Life Cycle Analysis Database.* Via: http://www.eiolca.net/. (See Table B25).
4. Energy = Mass * Energy Intensity
5. Emission = Mass * Emission Factor
6. Dones, R. and Frischknecht, R. (1998) *Life-cycle Assessment of Photovoltaic Systems: Results of Swiss Studies on Energy Chains.* Progress in Photovoltaics: Research and Applications. 6: pp. 117-125.

TABLE B20: USEFUL ELECTRICAL OUTPUT

SYSTEM POWER AND ENERGY			**Calculation**
Peak Direct Current Output[1]	8	kW	A
Lifetime	30	years	B
Design Projected Incident Radiation[1]	27,682	GJ/lifetime	C
Module DC Conversion Efficiency[1]	5.7%		D
Projected DC Module Generation	1,578	GJ	E=C*D
Degradation Losses[2]	120	GJ	F
Line losses[1]	219	GJ	G
Inverter losses[1]	74	GJ	H
Lifetime AC Generation	1,165	GJ	I = E-F-G-H
Lifetime AC Generation	0.324	GW_eh	J = I / (3600s/hr)

References and Notes:

1. Burdick, J. (2001) President, Burdick Technologies Unlimited, LLC, Personal Communications.
2. Estimate based on a 15% total degradation over 30 year module lifetime. Bertsche, G. (June 14, 2001) Regional Sales Manager, United Solar Systems Corporation, Personal Communications.

OPPORTUNITY LOSSES DUE TO LESS THAN OPTIMAL SLOPE AND ORIENTATION (PAGE 1 OF 3)

TABLE B21: SUMMARY

Method 1 - Opportunity Loss Due to Slope[1]	8.24%	
Method 1 - Opportunity Loss Due to Orientation[4]	0.36%	
Method 1 - Opportunity Loss[5]	8.63%	
Method 2 - Opportunity Loss Due to Slope & Orientation[4]	10.78%	
Opportunity Loss (Average of Methods 1 and 2)	**9.71%**	
Design Projected Direct Current Module Generation[6]	1,578	GJ
Potential DC Generation with Optimal Slope & Orientation[7]	**1,731**	GJ

TABLE B22: SLOPE OPTIMIZATION - METHOD 1[1]

	Slope	Insolation Rate Hbar_T (MJ/day)
Actual	18.4	18.44
Optimal	45	19.96

Opportunity Loss Due to Slope = (Optimal Insolation / Actual Insolation -1) = 0.082

Parameters[1:]
Hbar_T=H_BAR_T_LJ_(Hbar,Lat,n,Slope,GrRef)
Hbar=15.8 Average insolation on horizontal surface, Denver.
Lat=40.0
n=nDay_(3,15)
GrRef=.4

References and Notes:

1. Evaluated using references 2 and 3.
2. TRNSED Editor Program for TRNSYS. Version 3.002. Solar Energy Laboratory. University of Wisconsin - Madison.
3. Engineering Equation Solver. Version 5.179. F-Chart Software.
4. See Table B23
5. Opportunity Loss = (1 + Loss Due to Slope) * (1 + Loss Due to Orientation) - 1
6. See Table B20
7. Potential DC Generation = Design Projected Generation * (1 + Opportunity Loss)

OPPORTUNITY LOSSES DUE TO LESS THAN OPTIMAL SLOPE AND ORIENTATION (PAGE 2 OF 3)

TABLE B23: ORIENTATION OPTIMIZATION - METHOD 1

		Optimal		Actual	
		Due South (Az=0)		Azimuth = -8 deg	
HrAng	I (MJ/hr)	R_B	I_T (MJ/hr)	R_B	I_T (MJ/hr)
-82.5	0.105	1.910	0.201	3.197	0.336
-67.5	0.805	1.463	1.178	1.773	1.427
-52.5	1.533	1.400	2.146	1.558	2.388
-37.5	2.211	1.377	3.045	1.466	3.241
-22.5	2.681	1.367	3.665	1.411	3.783
-7.5	2.903	1.362	3.954	1.372	3.983
7.5	2.863	1.362	3.899	1.340	3.836
22.5	2.616	1.367	3.576	1.310	3.427
37.5	2.184	1.377	3.007	1.277	2.789
52.5	1.536	1.400	2.150	1.231	1.891
67.5	0.758	1.463	1.109	1.141	0.865
82.5	0.105	1.910	0.201	0.601	0.063
	20.3		28.131		28.030

Loss Due to Orientation = (Optimal Insolation / Actual Insolation -1) = 0.004

Parameters[1:]
"R_B=R_Beam_(Lat,n,HrAng,Slope,SurfAzAng)"
Lat=40.0
n=nDay_(3,15)
HrAng by Parametric Table
Slope=40
R_B0=R_Beam_(Lat,n,HrAng,Slope,0)
R_B8n=R_Beam_(Lat,n,HrAng,Slope,-8)

References and Notes:

1. Evaluated using references 2 and 3.

2. TRNSED Editor Program for TRNSYS. Version 3.002. Solar Energy Laboratory. University of Wisconsin - Madison.
3. Engineering Equation Solver. Version 5.179. F-Chart Software.

OPPORTUNITY LOSSES DUE TO LESS THAN OPTIMAL SLOPE AND ORIENTATION (PAGE 3 OF 3)

TABLE B24: SLOPE & ORIENTATION OPTIMIZATION - METHOD 2

		Optimal		Actual	
		(Az=0, B=40)		(Az=-8, B=18.4)	
HrAng	I (MJ/hr)	R_B	I_T (MJ/hr)	R_B	I_T (MJ/hr)
-82.5	0.105	1.910	0.201	2.143	0.225
-67.5	0.805	1.463	1.178	1.443	1.162
-52.5	1.533	1.400	2.146	1.338	2.051
-37.5	2.211	1.377	3.045	1.292	2.857
-22.5	2.681	1.367	3.665	1.266	3.394
-7.5	2.903	1.362	3.954	1.247	3.620
7.5	2.863	1.362	3.899	1.231	3.524
22.5	2.616	1.367	3.576	1.216	3.181
37.5	2.184	1.377	3.007	1.200	2.621
52.5	1.536	1.400	2.150	1.177	1.808
67.5	0.758	1.463	1.109	1.133	0.859
82.5	0.105	1.910	0.201	0.868	0.091
	20.3		28.131		25.393

Loss Due to Slope/Orientation = (Optimal Insolation / Actual Insolation -1) = 0.108

Parameters[1:]
R_B=R_Beam_(Lat,n,HrAng,Slope,SurfAzAng)"
Lat=40.0
n=nDay_(3,15)
HrAng by Parametric Table
Slope=40
R_B0=R_Beam_(Lat,n,HrAng,Slope,0)
R_B8n=R_Beam_(Lat,n,HrAng,Slope,-8)

References and Notes:

1. Evaluated using references 2 and 3.

2. TRNSED Editor Program for TRNSYS. Version 3.002. Solar Energy Laboratory. University of Wisconsin - Madison.
3. Engineering Equation Solver. Version 5.179. F-Chart Software.

TABLE B25: INPUT/OUTPUT ENERGY AND GREENHOUSE GAS INTENSITY

	Energy Intensity		CO_2-equiv. Intensity	
Item	**TJ/$1Mil(92)[1]**	**GJ/$(2000)[2]**	**Tonne per $1Mil(92)[1]**	**kg per MJ[3]**
Other repair & maintenance construction	8.085	0.0066	572.1	0.0708
Engineering, architectural & surveying services	2.804	0.0023	194.2	0.0692
Other business services	5.953	0.0048	392.4	0.0659
Power, distribution, & specialty transformers	19.974	0.0163	1448.6	0.0725
Sanitary Services	28.185	0.0230	1448.6	0.0514
Electrical industrial apparatus	14.316	0.0117	1016.0	0.0710
Electronic computers	6.563	0.0053	459.6	0.0700
HYBRIDS				
Installation (Including Roofing)				
Engineering, architectural & surveying services (80%)	2.804	0.0023	194.2	0.0692
Other repair & maintenance construction (20%)	8.085	0.0066	572.1	0.0708
		0.0031		**0.0695**
Operation and Maintenance				
Engineering, architectural & surveying services (80%)	2.804	0.0023	194.2	0.0692
Other repair & maintenance construction (20%)	8.085	0.0066	572.1	0.0708
		0.0031		**0.0695**

Reference and Notes:

1. Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001.
2. (Energy Intensity GJ / $ 2000) = (Energy Intensity TJ / $ 1992) * (1000 GJ/TJ) * (0.8148 $\$_{2000}$ / $\$_{1992}$)
3. (CO_2 Intensity kg/MJ) = [(CO_2 Intensity Tonne Mil$) * (1000 kg/Tonne)] / [(Energy Intensity TJ/Mil$) * ($10^6$ MJ/TJ)]