Life-Cycle Energy Cost and Greenhouse Gas Emissions for Gas Turbine Power

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FUSION TECHNOLOGY INSTITUTE

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Contents

Tables

Figures

Abstract

This study performs a life-cycle assessment on a modern gas turbine power plant to evaluate net energy and greenhouse gas emissions. The life-cycle includes natural gas production and transmission, fabrication of equipment and structural materials, plant construction, operation, and decommissioning. The result of the net energy analysis is an energy payback ratio (EPR), which is the ratio of useful electrical output to the total energy inputs. The EPR for the gas turbine is 4.1 and is limited by large energy investments associated with the fuel cycle. The gas turbine EPR is low compared to coal (11), fission (16), fusion (27), and wind turbine (23) technologies. The greenhouse gas emission rate is calculated using the inputs from the net energy analysis. Normalized over its life-cycle, the gas turbine emits 464 tonnes of carbon dioxide equivalent for every gigawatt-hour of electricity produced (tonne/GW_eh). This emission rate is lower than conventional coal (974 tonne/GW_eh), but higher than fission (15 tonne/GW_eh), fusion (9 tonne/GW_eh), and wind (14 tonne/GW_eh) technologies.

1.0 Introduction

Scientific opinion on climate change has reached a new level of concern. “It is not a question of whether the Earth’s climate will change, but rather when, where and by how much” [1], states Robert Watson, Chairman of the Intergovernmental Panel on Climate Change (IPCC). There is clear evidence that changes in climate variability indicators have already occurred. Global mean surface temperature has increased by between 0.3 - 0.6°C since the late 19th century [2]. In addition, global sea levels have risen by between 10 - 25 cm during the same period; much of which may be related to the temperature increase. According to the IPCC, these changes are “unlikely to be entirely natural in origin.” The balance of evidence suggests an identifiable human influence on global climate [2].

The observed atmospheric warming effect is credited to greenhouse gases, which allow incoming shortwave solar radiation to penetrate the atmosphere, but absorb the infrared radiation reflected back by the Earth’s surface. The infrared radiation, or heat, is trapped in the atmosphere causing the 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. In terms of total atmospheric warming impact, carbon dioxide (CO_2) is by far the most important anthropogenic gas, followed by methane (CH_4) and nitrous oxide (N_2O). While oceans and terrestrial plants regulate concentrations of CO_2 in the atmosphere [3], these natural processes absorb only about half of the anthropogenic emissions [4]. The excess is accumulating in the atmosphere, resulting in a drastic 28% increase in CO_2 concentration from levels that were relatively stable for the previous 1,000 years [2].

IPCC model simulations predict a global mean temperature increase between 1 - 3.5^{o}C, and sea level rise between 15 - 95 cm by the year 2100. The average rate of warming predicted for all scenarios is probably greater than any seen in the last 10,000 years [2]. The models also predict similar consequences in response to the warming. While individual events cannot be directly linked to human-induced climate change, the frequency and magnitude of certain events are expected to increase in a warmer world, such as:

- Increased water stress in areas of Africa, the Middle East and Europe,
- Decreased agricultural production in Africa and Latin America,
- Increased incidence of vector-borne diseases in tropical countries,
- Rising sea levels in small island states and low-lying deltaic areas resulting in the displacement of tens of millions of people, and
- Structural and functional changes in critical ecological systems, particularly coral reefs and forests [1].

The National Assessment Synthesis Team [5] recently projected the potential for a summertime heat index increase between 5 - 15^{o}F across the eastern U.S. by 2100. This change could result in summertime conditions in New York resembling those currently in Atlanta, Atlanta summertime conditions resembling those in Houston, and Houston summertime conditions like those in Panama [5].

Whether international accord can be reached in time to prevent these potential consequences remains unanswered. The U.S. Senate voted unanimously against commitments to prevent climate change, not because they doubt the seriousness of the impact, but because they perceive an inequitable plan for implementation. Other industrial nations agree that their best intentions are wasted without commitments from developing countries. However, developing countries fear the economic impacts of making these commitments. The two sides have forced an international stalemate.

The United States is the world's largest greenhouse gas contributor, accounting for 25% of global emissions [3]. The vast majority of U.S. emissions result from energy consumption (Figure 1) of which electricity comprises a significant portion (Figure 2). Electric utilities consume 25% of the primary U.S. energy and are the largest single source of greenhouse gas emissions [6]. In 1998, 40% of U.S. CO_2 emissions were attributed to the combustion of fossil fuels by electric utilities [7]. Globally, U.S. electric utilities accounted for about 10% of the total anthropogenic greenhouse gas emissions [3].

No federal regulations are currently proposed to reduce U.S. greenhouse gas emission. Electric utilities, however, are controlled to a large extent by state and municipal governments. Great strides can be achieved at this level, especially when combined with residential and commercial energy-conservation efforts. Electric utilities have a tremendous impact on greenhouse gas emissions, but they also represent a tremendous opportunity for climate change mitigation. In the absence of federal leadership, policymakers at state and local levels must incorporate an understanding of climate change causes and effects into their regulation of electric power.

Figure 1: 1998 Components of U.S. Greenhouse Gas Emission (Percent CO_2-Equivalent)

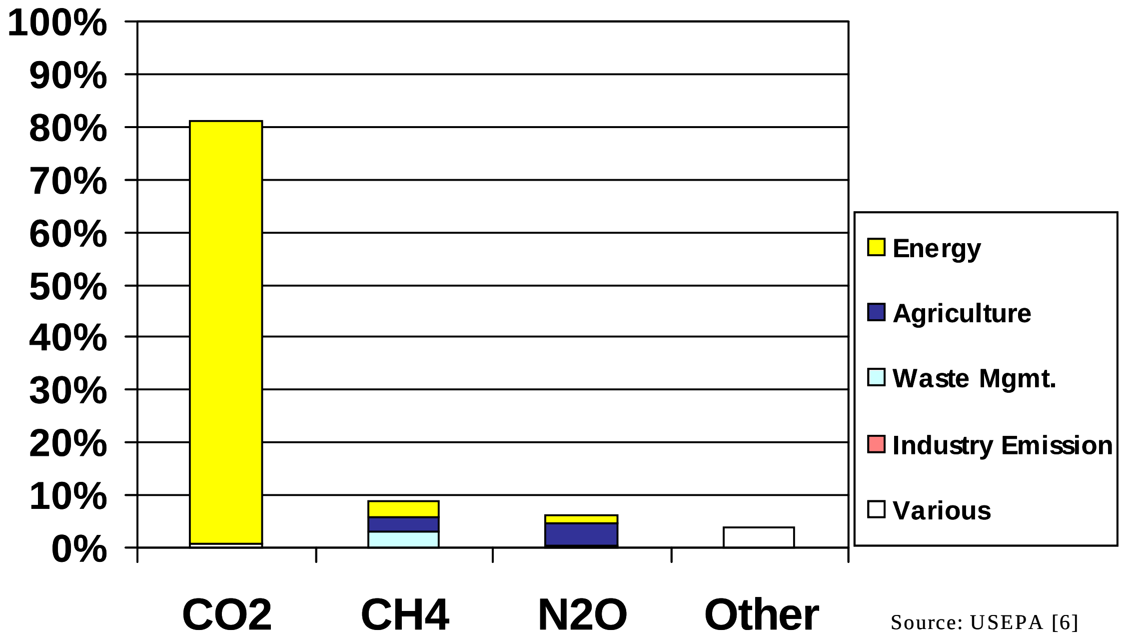
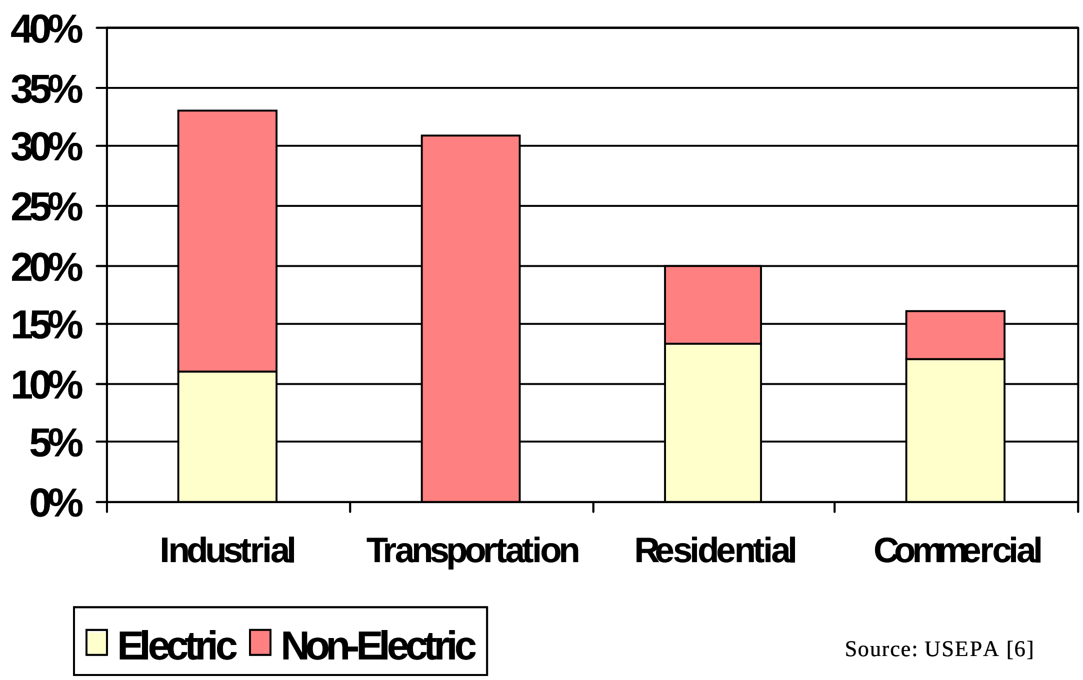


Figure 2: 1998 U.S. CO_2 Emissions from Fossil Fuels



2.0 Natural Gas Powered Electricity Generation

Natural gas is the fastest growing fuel for electricity generation as shown in Table 1. U.S. electricity generation using natural gas has increased by over 40% since 1990, and currently comprises about 15% of the electricity mix [8]. U.S. electricity consumption is expected to continue growing for the next 20 years with natural gas power plants providing the majority of the new capacity. The Energy Information Agency projects that 90% of an estimated 1,000 new generating plants will be combined cycle or combustion turbine technology fueled by natural gas, or both oil and gas [9].

Table 1: 1998 U.S. Electricity Generation and CO_2 Emission [8]

Fuel Source	1998 Generation (kWh x 10^9)	Change from 1997 (kWh x 10^9)	1998 Emission (MMT CO_2)*	Change from 1997 (MMT CO_2)*
Coal	1,873	+29.7	1,796	+19.4
Natural Gas	497	+44.6	288	+30.5
Petroleum and Other	154	+ 41.9	111	+29.6
Non-Fossil Fuel	1,095	+7.72	--	--
Total	3,619	+123.9	2,221	79.5

*MMT CO_2 = million metric tonnes of carbon dioxide equivalent.

Electricity consumption in Wisconsin is also expected to show continued growth, resulting in a projected 40% increase in electric utility greenhouse gas emissions between 1990 and 2010 [10]. In 1998, Wisconsin generated only 2.9% of its electricity using natural gas; however, this percentage has more than doubled since 1996. This rapid growth is expected to continue into the near future due to the increased use of natural gas turbine technology [11].

The present study evaluates two important metrics for natural gas turbine power: energy payback ratio and greenhouse gas emission rate. A description of these methods is provided in Sections 3 and 4. Section 5 provides a detailed summary of the data and calculations. Section 6 discusses results including a comparison of gas turbines versus alternative technologies. Supporting calculations are included in Appendix A.

The facility used as the basis of this study is a combined cycle combustion turbine plant. While gas turbines are typically utilized to meet intermediate or peak load, this study assumes that the plant is utilized for base load, to allow for comparison to alternative technologies. This study assumes that the gas turbine plant operates at 75% capacity and has a 40 calendar year lifetime (i.e., 30 full power years). The assumed capacity and lifetime are somewhat higher than a typical gas turbine plant [12], which results in a slightly more favorable energy payback ratio and greenhouse gas emission rate.

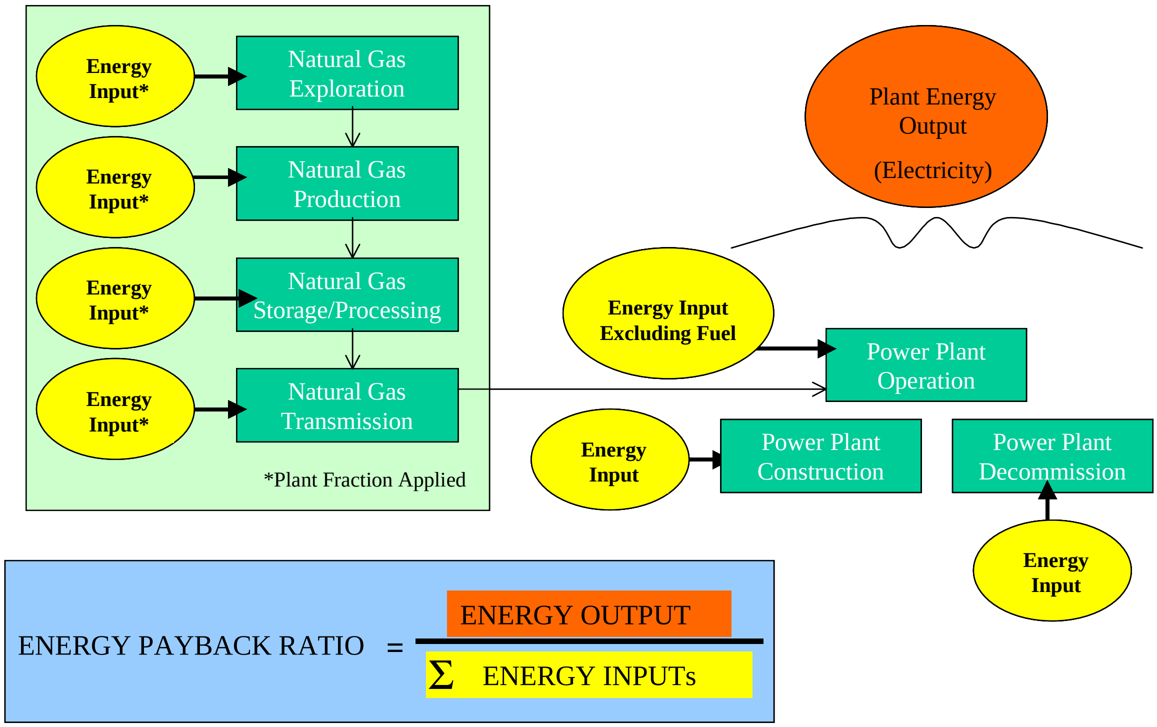
3.0 Net Energy Analysis

Net Energy Analysis (NEA) is a comparison of the useful energy output of a system to the total energy consumed by the system over its life-cycle. A life-cycle approach includes "upstream" processes such as the mining of raw materials, and "downstream" processes such as plant decommissioning. NEA is an important tool for evaluating energy options with consideration of ultimate resource availability. It is especially relevant to natural gas, where domestic resources are projected to last about another 60 years at current consumption rates [11].

In the case of a gas turbine power plant, the life-cycle includes natural gas production and transmission, fabrication of equipment and structural materials, plant construction, operation, decommissioning, and land reclamation. 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 [13]. The ratio of the useful output to the inputs is termed the "Energy Payback Ratio" [14]. Figure 3 illustrates the natural gas life-cycle and energy payback ratio.

Determining the output energy is a simple calculation based on the average power output of the plant. Determining the energy inputs is a much more rigorous process for which this study employs two basic methods called Input/Output (I/O) and Process Chain Analysis (PCA).

Figure 3: Natural Gas Turbine Life-Cycle and Energy Payback Ratio



The Input/Output (I/O) method is used to correlate dollar cost to energy use. An input/output model divides the entire economy into distinct sectors. These sectors are the basis for a matrix, which distributes the total cost of outputs and total energy inputs of the U.S. economy. For a given dollar output from an individual sector, the model can provide the total energy consumed directly and indirectly throughout the economy [15]. For example, $1 million of oil and gas field machinery and equipment purchases requires the average consumption of 17.2 terajoules of energy throughout the economy. This study and the example above utilized the Economic Input-Output Life Cycle Assessment (EIOLCA) model developed within the Green Design Initiative at Carnegie Mellon University [16]. The EIOLCA model is based upon the 1992 Department of Commerce's 485 x 485 commodity input-output model of the U.S. economy [17].

Process Chain Analysis evaluates the material and energy flows for each process within the system life-cycle [14]. When possible, actual data for energy expended during a process is utilized. To determine the energy required for system materials, the mass of material is multiplied by an embodied energy factor (i.e., gigajoules (GJ)/tonne material). This factor accounts for the energy required to mine, mill, and fabricate the raw material.

Process Chain Analysis is generally considered more accurate than the Input/Output method. However, it is difficult to evaluate an entire life-cycle using PCA, because data on all the materials used and energy consumed is not readily available. Cost data is frequently available, making the input/output method more applicable for many processes. This study utilizes PCA as a first alternative, then uses the I/O method to complete missing portions of the life-cycle. Approximately 87% of the total energy inputs calculated in this study were determined using the PCA method. While a larger number of items within the life-cycle utilized the I/O method, their combined energy accounted for only about 13% of the total.

4.0 Greenhouse Gas Emission Rates

The energy requirements calculated for each phase of the life-cycle can be used to estimate the greenhouse gas emissions. This methodology provides a better estimate of a technology's greenhouse gas impact than simply estimating plant emissions. For this study, the life-cycle emissions are normalized in terms of tonnes CO_2-equivalent emitted per gigawatt-hour electricity produced (tonne/GW_eh), allowing for comparison against alternative technologies.

Carbon dioxide is a byproduct of fossil fuel combustion. Because the vast majority of U.S. energy is provided via fossil fuels, each energy input within the life-cycle has corresponding CO_2 emissions. Carbon dioxide is the most significant greenhouse gas based on total global emissions. Methane and N_2O are actually stronger warming agents, but have far lower global emission rates. These less important gases are accounted for in terms of CO_2-equivalent based on their global warming potential as described below.

When averaged over 100 years, CH_4 has a 21 times stronger global warming potential than CO_2 [18], meaning that 1 tonne of CH_4 emissions can be accounted for as 21 tonnes of CO_2-equivalent emissions. Methane is the main component of natural gas and is released during natural gas production, processing, and transmission. Because electric utilities consume 15% of U.S. natural gas [19], they are indirectly responsible for a significant portion of the CH_4 emissions from this source. In addition, CH_4 is released in small quantities at generating plants as a product of incomplete combustion.

Nitrous oxide has a 310 times stronger global warming potential than CO_2 [2]. Nitrous oxide is a product of the reaction that occurs between nitrogen and oxygen during fuel combustion [8]. High temperatures destroy almost all nitrous oxide; therefore, power plant emissions contain a very low concentration of this molecule [2].

5.0 Life-Cycle Analysis

5.1 Fuel Cycle

The natural gas fuel cycle includes exploration, production, storage, processing, and transmission (Figure 3). A fraction of the total U.S. energy consumed during each phase of the fuel cycle is applied to the gas turbine plant, based on the percentage of U.S. natural gas delivered to the plant.

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 (dollars per billion cubic feet) [20], and an I/O energy intensity for natural gas exploration. Carbon dioxide emissions were estimated using the energy estimate for exploration (GJ) multiplied by an I/O emission rate for exploration (tonnes CO_2-equiv/GJ).

During field production, wells are used to withdraw natural gas from underground formations. Production energy inputs were estimated primarily using PCA. 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 [21]. Greenhouse gas emissions occur both as the byproduct of natural gas combustion (CO_2), and as fugitive emissions (CH_4 leaks) from processing equipment [22]. 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 [23]. 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 [24]. However, because this process is often 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 gas turbine life-cycle. Processing inputs include the energy used for water, acid gas, and nitrogen removal [25]. As with production, fuel combustion and fugitive losses account for the vast majority of energy input and greenhouse gas emissions from processing.

The U.S. has an extensive natural gas transmission pipeline network consisting of approximately 300,000 miles of pipe [22]. 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.

As with production and processing, the direct consumption of natural gas is the primary source of CO_2 emissions from transmission. Methane is also emitted during transmission as fugitive losses from compressor stations, metering and regulating stations, and pneumatic devices [32]. The emissions resulting indirectly from pipeline and equipment construction and operation contribute only a small fraction of the total emissions. The following table provides a summary of fuel cycle energy inputs.

Table 2: Fuel Cycle Energy Requirements

Process	**Life-Cycle Energy Input (GJ)**
Natural Gas Exploration	9,278,251
Natural Gas Production	76,120,196
Natural Gas Storage and Processing	14,032,191
Natural Gas Transmission	36,847,421
Fuel Cycle Total	**136,278,058**

5.2 Plant Materials, Construction, and Operation

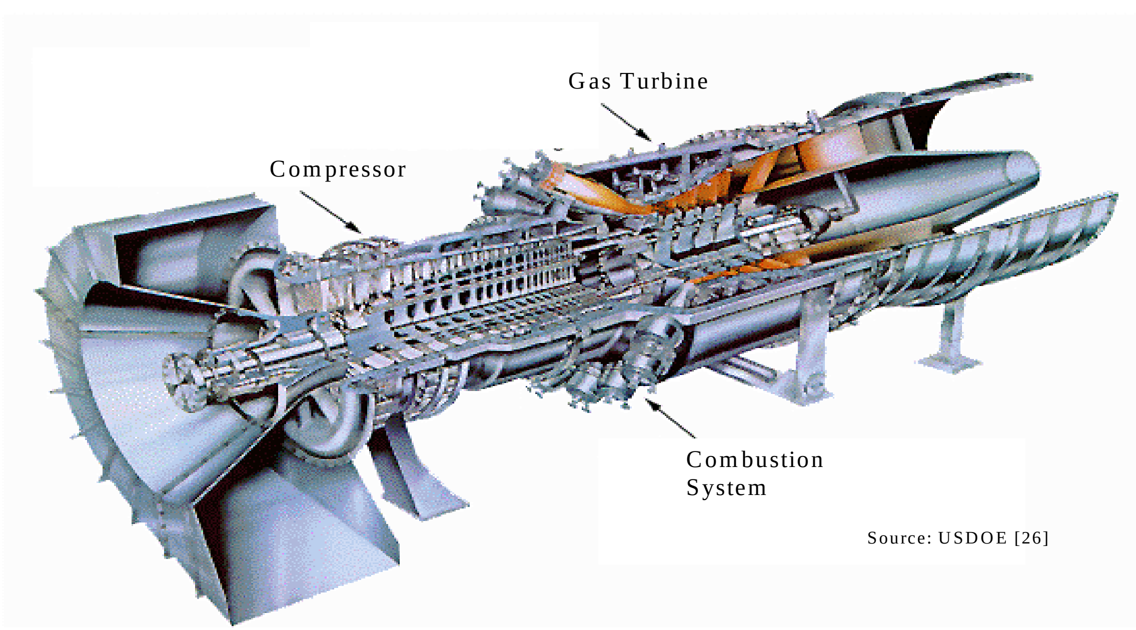
5.2.1 Gas Turbine Reference Plant Description

The power plant used as the basis for this study is a 2 x 1 combined cycle combustion turbine plant. The "Reference Plant" is currently being constructed by Aquila Energy in Cass County, Missouri. The system consists of two Siemens Westinghouse 501FD combustion turbines (CTs) and a nominal 250 MW steam turbine. Both combustion turbines are coupled with heat recovery steam generators (HRSGs). The HRSGs utilize duct burners as an inexpensive way to add peaking capacity [12].

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 (Figure 4). 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 CT generators, then is used to turn the steam turbine, producing additional electricity. The exhaust of the steam turbine is directed to a water-cooled condenser [12].

The power output from a gas turbine is highly temperature dependent. The Aquila plant is designed to generate 587 MW at ambient air conditions of 99^{o}F, but is expected to be capable of providing 658 MW at 2^{o}F [12]. For purposes of this study, it is assumed that the plant will operate at 75% capacity annually, relative to a nominal output of 620 MW net power. Thermal efficiency also varies with temperature and operating conditions, and is assumed to be 48% for this study.

Figure 4: Advanced Gas Turbine



The plant buildings include a general services building, electrical equipment building, and water treatment building. 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 houses water treatment equipment, chemical feed equipment, firewater pumps, and treatment equipment controls. The combustion turbines and steam turbine are located outdoors [12].

5.2.2 Reference Plant Energy Inputs

An inventory of plant structural materials was compiled including quantities of pipe, structural steel, and concrete [27]. 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 3, 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.

Table 3: Gas Turbine Plant Material Energy Requirements*

Element or Alloy	Mass [27] Tonnes	Embodied Energy** GJ/Tonne	Energy Totals GJ
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	1,392	53.1	73,948
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**		**125,922**

* Reference plant of 620 MW_e.
** References for embodied energy factors are included in Appendix B.

The energy requirements for plant construction, operation, and maintenance were estimated by the I/O method using cost data and maintenance schedules provided by Aquila Energy [12]. It is important to note that the fuel consumed to produce electricity is excluded by convention from the net energy analysis. Table 4 provides a summary of the items and energy inputs associated with plant operation and maintenance (O&M). Figure 5 shows the distribution between the energy inputs for plant materials and equipment, construction, and operation.

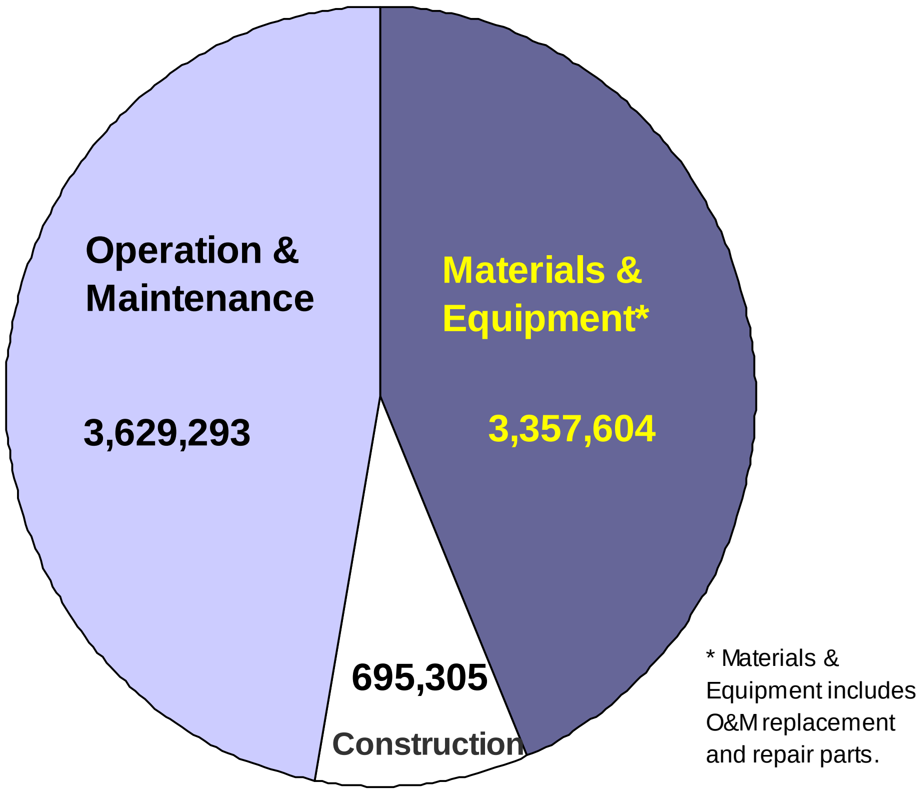
Table 4: Plant Operation Energy Requirements*

Item	**Life-cycle Energy Input (GJ)**
Water Supply & Treatment	625,621
Staff Labor	519,967
Major Maintenance	1,710,199
Routine Maintenance	185,687
Materials & Supplies	247,122
Contract Services	20,289
Administrative Overhead	130,288
Other Expenses	13,671
Startup Costs	176,508
Maintenance Subtotal	***3,629,293***
Replacement Parts	1,713,677
Repair Parts	661,200
Parts Subtotal	***2,374,877***
Total	**6,004,170**

*Based on O&M schedule provided by Aquila Energy [12] for a 620 MW_e reference plant.

Carbon dioxide emissions were estimated for plant construction and operation based on a combination of emission factors for raw materials (tonne CO_2/tonne material) and I/O emission factors (tonne/GJ). Unlike the net energy analysis, the natural gas consumed to generate electricity is considered for the calculation of greenhouse gas emissions. Emissions from natural gas combustion are estimated with EPA emission factors and are the largest contributor to life-cycle emissions.

Figure 5: Life-Cycle Energy Investments in Materials, Construction, & Operation



5.3 Plant Decommissioning and Land Reclamation

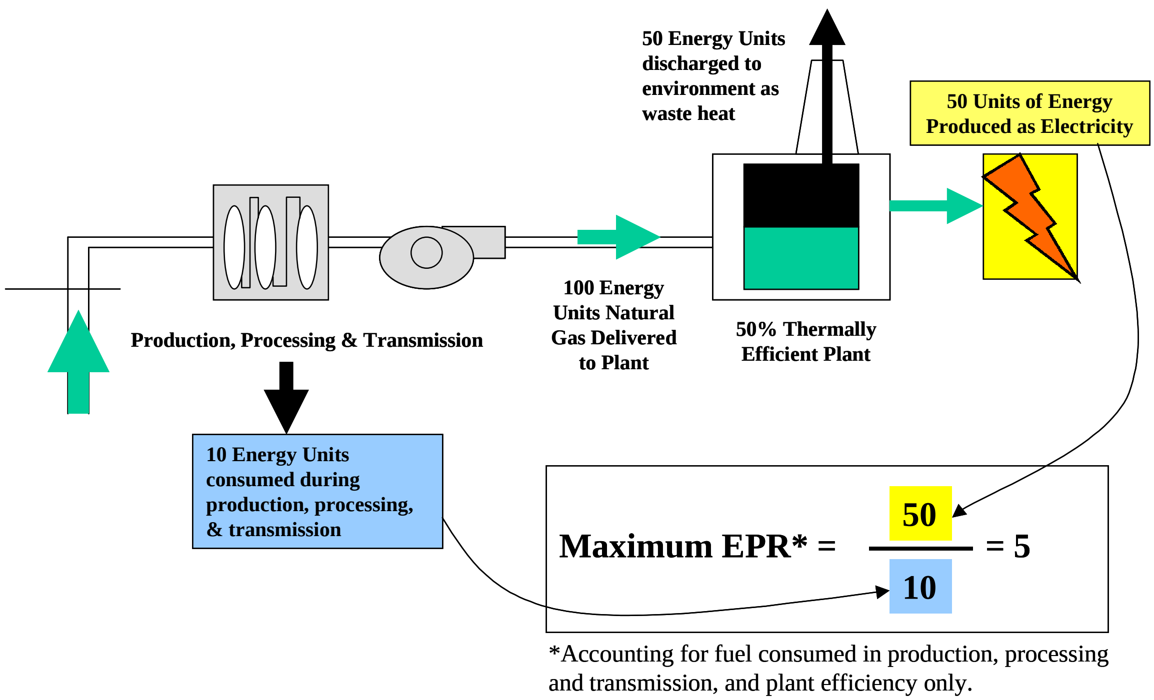
The energy required to decommission the plant was estimated using the I/O method. The cost for decommissioning was estimated as a combination of equipment dismantling and building demolition [12, 28]. Land reclamation refers to returning the land to its natural state. For the gas turbine life-cycle, 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. Greenhouse gas emissions from decommissioning and land reclamation were estimated using I/O CO_2 emission factors. Emissions from these sources are a relatively minor portion of the total life-cycle emissions.

6.0 Results and Discussion

6.1 Net Energy Analysis

The fuel cycle is the most significant portion of the gas turbine life-cycle when evaluating the energy inputs. For every 10 cubic feet of natural gas delivered to end users (e.g., delivered to the reference plant), 1 cubic foot is consumed during production, processing, and transmission [21]. This massive energy investment has a dramatically limiting effect on the energy payback ratio as illustrated in Figure 6.

Figure 6: Energy Payback Ratio (EPR) for Gas Turbine Life-Cycle is Limited by Fuel Production, Processing, and Transmission



The remainder of the life-cycle (plant construction, operation, decommissioning, and land reclamation) accounts for only about 5% of the total energy inputs. Table 5 provides a more detailed breakdown of the energy investment by item, while Figure 7 illustrates the distribution of energy inputs for the gas turbine life-cycle.

Table 5: Life-Cycle Energy Requirements are Dominated by the Fuel Cycle

Process	**Life-cycle Energy Input (GJ)**
Natural Gas Exploration	9,278,251
Natural Gas Production	76,120,196
Natural Gas Storage & Processing	14,032,191
Natural Gas Transmission	36,847,421
Fuel Cycle Subtotal	***136,278,058***
Plant Construction & Materials	1,678,033
Plant Operation & Maintenance*	6,004,170
Plant Decommission	42,714
Land Reclamation	16,507
Plant Subtotal	***7,741,424***
Total	**144,019,482**

*Includes replacement and repair parts

The energy investment from the gas turbine life-cycle is normalized to an output of one gigawatt full power year, to allow for comparison against alternative technologies. As shown in Figure 8, the gas turbine life-cycle has a much higher normalized energy investment than alternative technologies. The gas turbine life-cycle is similar to coal and fission in that the majority of energy investment is associated with the fuel cycle. Fusion and wind have little and no energy investment in the fuel cycle respectively, but have a higher proportion of energy input associated with construction [14].

Figure 7: Normalized Net Energy Investment in Gas Turbine Life-Cycle

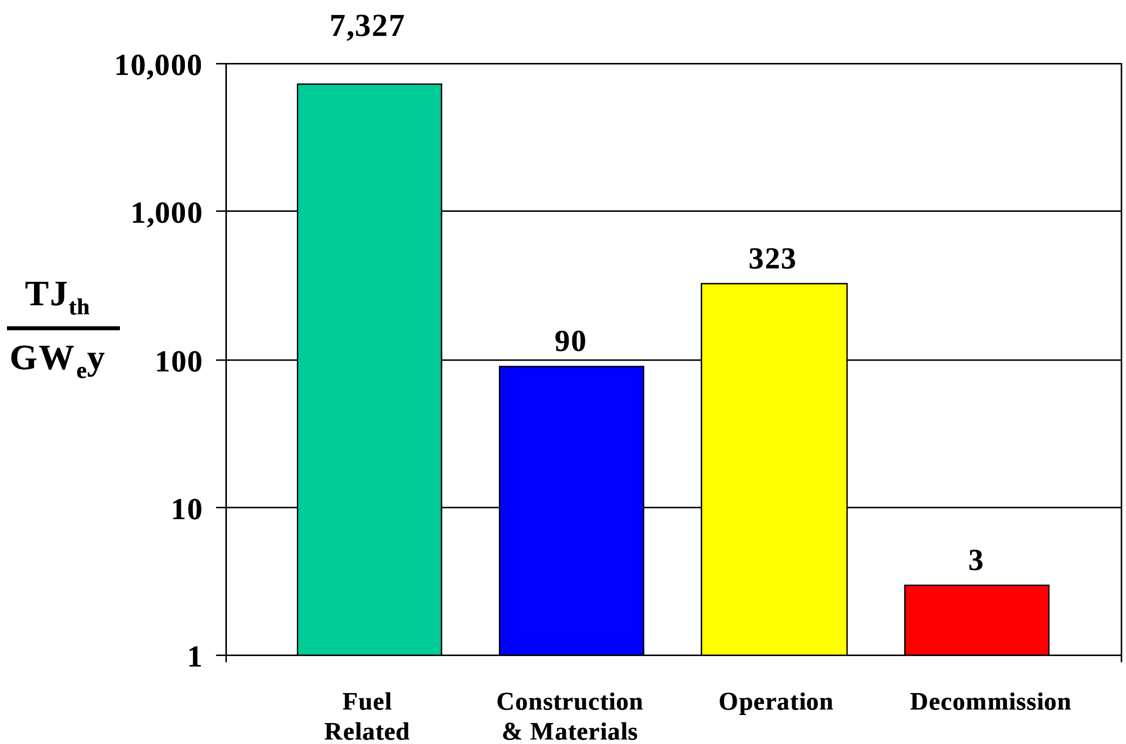
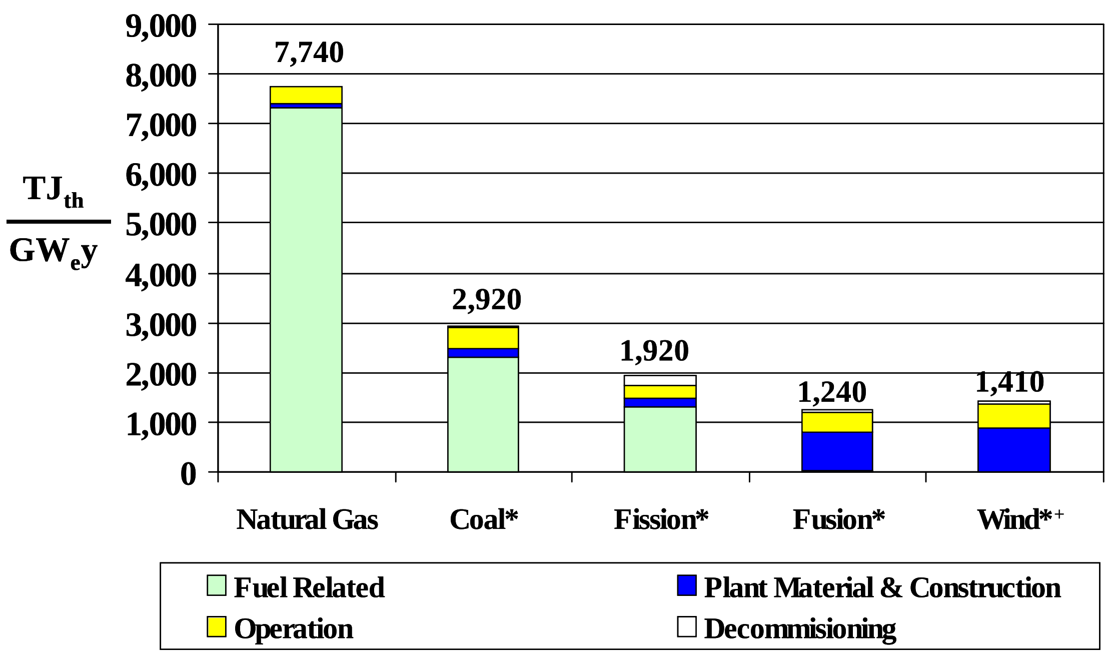


Figure 8: Normalized Energy Investment Comparison



* Previous Work by: S. White, University of Wisconsin [36]

+ Wind analysis excludes energy storage

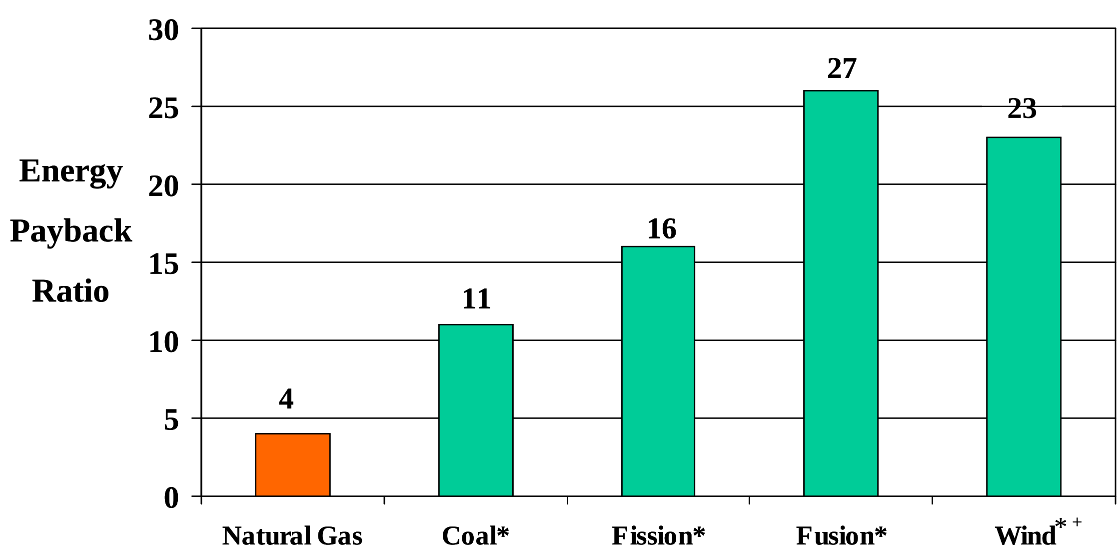
The high-energy investment for the gas turbine life-cycle results in a correspondingly low energy payback ratio of 4.1, as illustrated in Figure 9. Figure 10 compares the EPR for the gas turbine against alternative technologies.

Figure 9: Energy Payback Ratio for Gas Turbine Life-Cycle

Lifecycle Energy Inputs	Lifecycle Output
Fuel Related: 136,000 TJ_{th} Construction & Materials: 1,680 TJ_{th} Operation: 6,000 TJ_{th} Decommission: 59.0 TJ_{th} Total: 144,000 TJ_{th}	Net Electrical Output: 587,000 TJ_e

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

Figure 10: Energy Payback Ratio Comparison to Previous Work



*Previous Work by: S. White, University of Wisconsin[35]

+Wind analysis for BR-I [35] excludes energy storage

6.2 Greenhouse Gas Emission Rate

The energy inputs calculated for the net energy analysis provide the basis for calculating greenhouse gas emissions. The normalized emission rate for the gas turbine life-cycle is 464 tonnes CO_2-equivalent per GW_eh (tonne/GW_eh). The estimated emission rate from this study is slightly higher than previously published studies by Audus (410 tonne/GW_eh) [29], Macdonald (410 tonne/GW_eh) [30], and Wilson (367-459 tonne/GW_eh) [31]. The previously published reports exclude many of the indirect energy inputs considered in this study, which contribute approximately 10 tonne/GW_eh.

Fuel combustion during plant operation is the largest contributor to the greenhouse gas emission rate, accounting for 82% of emissions or 382 tonne/GW_eh. The fuel cycle also contributes significantly, comprising 17% of the life-cycle emissions, or 77 tonne/GW_eh. Plant construction, O&M, decommissioning, and land reclamation comprise the remaining 1% (5 tonne/GW_eh). Figure 11 illustrates the greenhouse gas emissions from each phase of the life-cycle.

Of the 77 tonne/GW_eh of CO_2-equivalent emissions attributed to the fuel cycle, 40 tonne/GW_eh are the result of methane leaks. Estimates of methane leakage from the natural gas fuel cycle vary greatly, ranging from 1% - 11% of production [18]. Most of the commonly cited estimates range from 1% - 4% [32]. The assumed leakage rate has a significant impact on life-cycle emissions. This study utilized USEPA estimates [22] of CH_4 emissions, which correspond to a 1.4% leakage rate. Figure 12 shows the resulting life-cycle emission rates when using various estimates for methane leakage between 1% - 5%.

Figure 11: Greenhouse Gas Emissions (Tonne CO_2-equivalent / GW_eh)

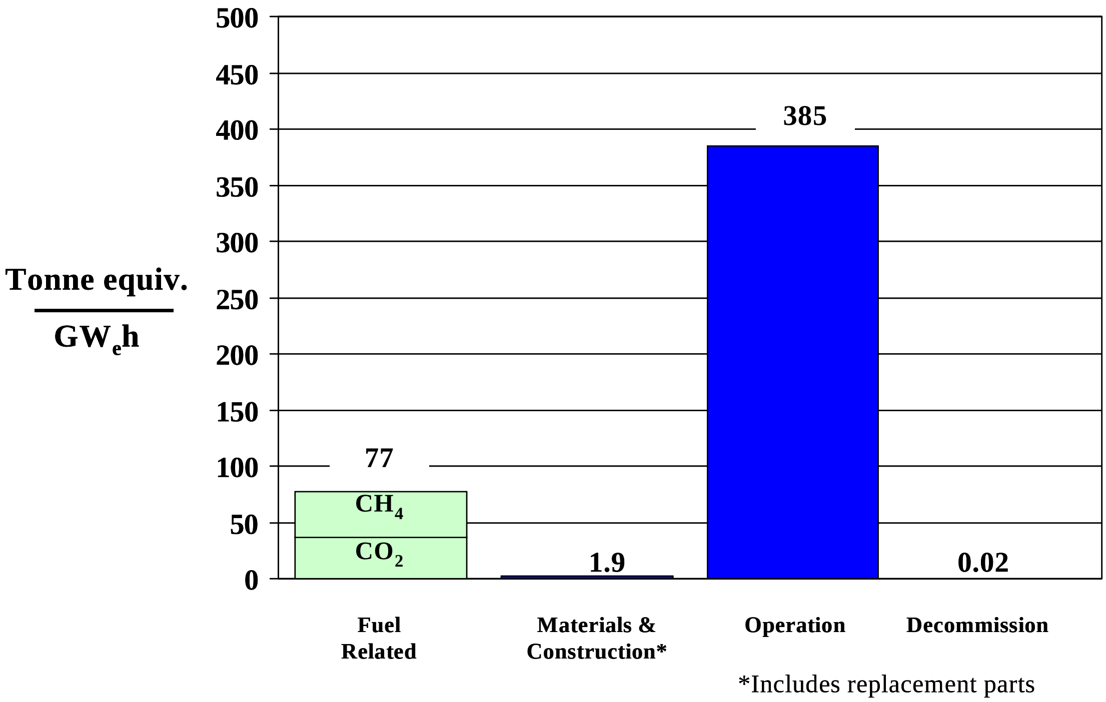


Figure 12: Life-Cycle Emission Rate is Impacted by the Assumed Rate of CH_4 Leakage During the Fuel Cycle (Tonne CO_2-equivalent / GW_eh)

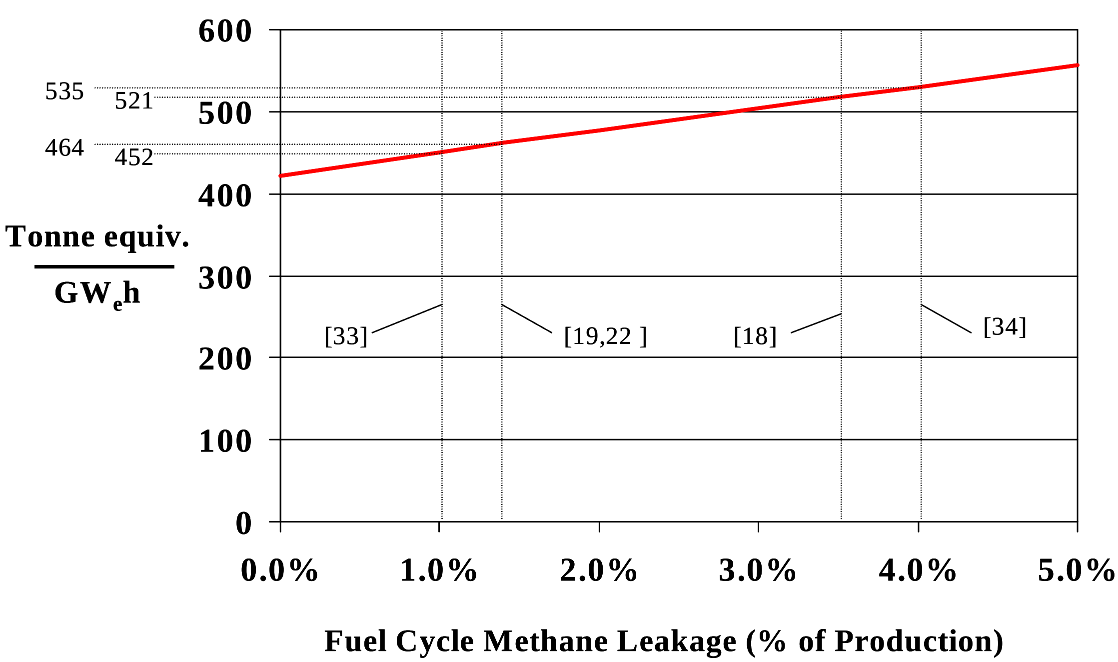
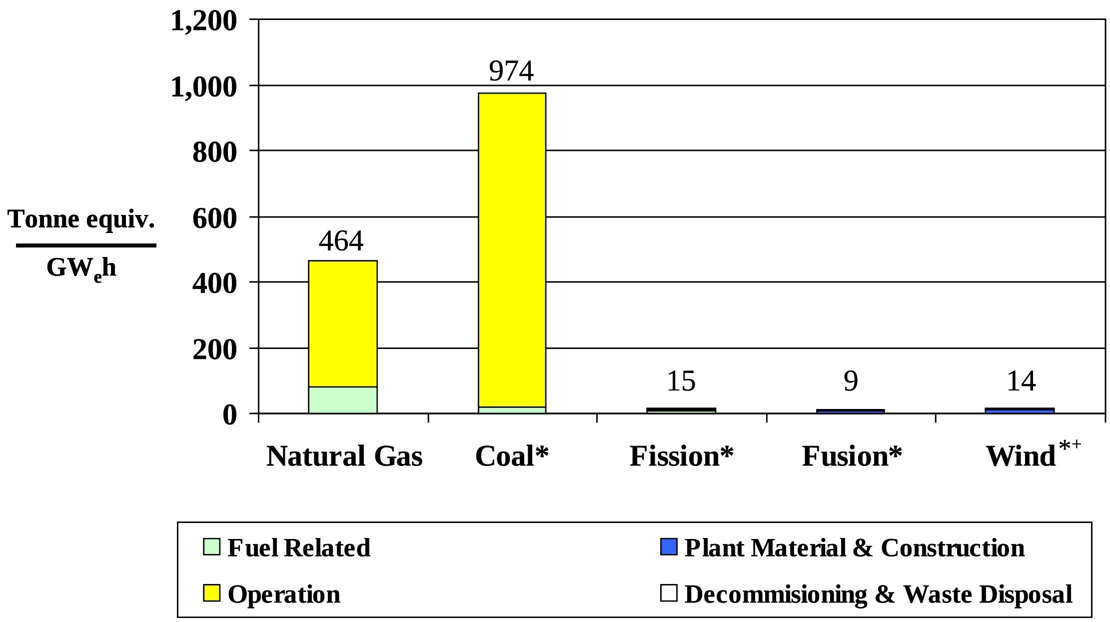


Figure 13 compares the gas turbine life-cycle emission rate to other technologies. Coal and gas (fossil fuel technologies) have significant emissions associated with operation (e.g., fuel combustion). The gas turbine emission rate of 464 tonne/GW_eh compares favorably to conventional coal at 974 tonne/GW_eh. However, the non-fossil fuel technologies have drastically lower emission rates: 9 tonne/GW_eh for fusion, 14 tonne/GW_eh for wind, and 15 tonne/GW_eh for fission [35].

Figure 13: Greenhouse Gas Emission Comparison (Tonne CO_2-equivalent / GW_eh)



*Previous Work by: S. White, University of Wisconsin [35]

+Wind analysis for BR-I [35] excludes energy storage.

6.3 Conclusion

The energy payback ratio for the gas turbine life-cycle is limited by the use of extensive quantities of natural gas during production, processing, and transmission phases of the fuel cycle. The EPR for the gas turbine life-cycle (4) is low, therefore, compared against coal (11), fission (16), fusion (27), and wind turbine (23) technologies [35]. Greenhouse gas emission rates for the gas turbine life-cycle (464 tonne/GW_eh) also compare unfavorably against non-fossil fuel technologies (9-15 tonne/GW_eh).

The life-cycle emission rate for the gas turbine (464 tonne/GWeh) is significantly lower than the life-cycle emission rate for conventional coal (974 tonne/GWeh). Considering only the emissions from power plant fuel combustion, CO_2 emissions from the gas turbine plant are 40% of those from the conventional coal plant. However, a complete life-cycle assessment increases the gas turbine emission rate more dramatically (+21%) than the coal emission rate (+2%) [14]. The resulting gas turbine life-cycle emission rate is 48% of the life-cycle emission rate for conventional coal.

6.4 Acknowledgments

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Gas Turbine Lifecycle Summary Calculations
Natural Gas Exploration

Net Energy Analysis

Plant Exploration Loss = Required Production* Exploration Energy Losses[1]
[9,278,251 GJ] = [1,440,701,340 GJ] * [0.0064 GJ consumed / GJ nat gas produced]

where:
Exploration Energy Losses = Cost of Adding Proved Reserves * I/O Nat Gas exploration[2]
[0.0064 GJ consumed / GJ nat gas produced] = [0.72 $/GJ] * [0.00894 GJ/$]

Greenhouse Gas Emissions

Plant Exploration Emissions = Plant Exploration Loss * I/O Exploration Emission Factor[2]
[655,277 tCO2e] = [9,278,251 GJ] * [0.0706 tCO2e / GJ]

Notes:
GJ = Giga-Joules
tCO2e = tonnes Carbon Dioxide Equivalent

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1. The Coastal Corporation. (1998) *1998 Annual Report* . Houston, TX.
2. Green Design Initiative, Carnegie Mellon University, via http://www.eicola.net/.

Gas Turbine Lifecycle Summary Calculations

Natural Gas Production

Net Energy Analysis

Losses from Production = Fuel Losses + Pipeline Material Losses + Installation Losses + Engineering & Admin Losses
[76,120,196 GJ] = [75,751,552 GJ] + [156,255 GJ] + [111,159 GJ] + [101,229 GJ]

where:
Production Fuel Loss = Fuel Delivered to 620 MW Plant * (Vent & Flare Loss[1] + Lease Fuel Loss[1])
[75,751,552 GJ] = [1,222,020,000 GJ] * ([1.3%] + [4.9%])

Production Pipeline Material Embodied Energy Loss = Production Pipeline Embodied Energy[2,3] * Plant fraction of US Nat Gas[1] / Pipeline lifetime * Plant Lifetime
[156,255 GJ] = [60,929,512 GJ] * [0.192%] / [30 yrs] * [40 yrs]

Production Pipeline Installation Energy Loss = Production Pipeline Labor Energy[2,4,5] * Plant fraction of US Nat Gas[1] / Pipeline lifetime * Plant Lifetime
[111,159 GJ] = [43,345,060 GJ] * [0.192%] / [30 ys] * [40 yrs]

Production Pipeline Engineering & Admin Energy Loss = Production Pipeline E&A Energy[2,4,5] * Plant fraction of US Nat Gas[1] / Pipeline lifetime * Plant Lifetime
[101,229 GJ] = [39,473,023 GJ] * [0.192%] / [30 yrs] * [40 yrs]

Natural Gas Production (Continued)

Greenhouse Gas Emissions

Production Related Emissions = Fuel Related Emissions + Pipeline Material Emissions + Installation Emissions + Engineering & Admin Emissions
[5,686,521 tCO2e] = [5,660,313 tCO2e] + [11,484.2 tCO2e] + [7,849 tCO2e] + [6,875 tCO2e]

where:
Fuel Related Emissions = CO2 emission + CH4 emission + N2O emission
[5,660,313 tCO2e] = [3,245,965 tCO2e] + [2,394,437 tCO2e] + [19,911 tCO2e]

CO2 emission = Production Fuel Loss * (1 - fraction methane leaks[1,6]) * Emission Factor for NG Combustion[7]
[3,245,965 tCO2e] = [75,751,552 GJ] * [0.914] * [0.0469 tonne/GJ]

CH4 emission = Global Warming Potential[8] * U.S. Field Production CH4 Emissions[6] * Plant % of US Nat Gas Deliveries[1] * Plant Lifetime
[2,394,437 tCO2e] = [21] * [1,700,000 tonnes] * [0.168%] * [40 calendar years]

N2O emission = Global Warming Potential[8] * Plant Production Fuel Loss * (1 - fraction methane leaks[1,6]) * Emission Factor for NG Combustion[7]
[19,911 tCO2e] = [310] * [75,751,522 GJ] * [0.914] * [9.27E-7 tonne/GJ]

Pipeline Material Emissions = Production Pipeline Material Embodied Energy Loss * I/O Pipe Emission Factor[5]
[11,484 tCO2e] = [156,255 GJ] * [0.0735 tonneCO2-equiv / GJ]

Installation Emissions = Production Pipeline Installation Energy Loss * I/O gas well maintenance Emission Factor[5]
[7,849 tCO2e] = [111,159 GJ] * [0.0706 tonneCO2-equiv / GJ]

Engineering & Admin Emissions = Production Pipeline Engineering & Admin Energy Loss * I/O Eng & Admin Pipe Emission Factor[5]
[6,875 tCO2e] = [101,229 GJ] * [0.0679 tCO2e / GJ]

Notes:
GJ = Giga-Joules
tCO2e = tonnes Carbon Dioxide Equivalent

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2. Office of Pipeline Safety. 1998 Database.
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Gas Turbine Lifecycle Summary Calculations
Natural Gas Storage & Processing

Net Energy Analysis

Storage & Processing Fuel Loss = Fuel Delivered to 620 MW Plant * Processing Plant Fuel Loss[1,2,3,4]
[14,032,191 GJ] = [1,222,020,000 GJ] * [1.15%]

Greenhouse Gas Emissions

Fuel Related Emissions = CO2 emission + CH4 emission + N2O emission
[1,591,135 tCO2e] = [601,501 tCO2e] + [985,944 tCO2e] + [3,690 tCO2e]

where:
CO2 emission = Storage & Processing Fuel Loss * (1 - fraction methane leaks[1,5]) * Emission Factor for NG Combustion[6]
[601,501 tCO2e] = [14,032,191 GJ] * [0.915%] * [0.0469 tonne/GJ]

CH4 emission = Global Warming Potential[7] * U.S. Storage & Processing CH4 Emissions[5] * Plant % of US Nat Gas Deliveries[1] * Plant Lifetime
[985,944 tCO2e] = [21] * [700,000 tonnes] * [0.168%] * [40 yrs]

N2O emission = Global Warming Potential[7] * Storage & Processing Fuel Loss * (1 - fraction methane leaks[1,5]) * Emission Factor for NG Combustion[6]
[3,690 tCO2e] = [310] * [14,032,191 GJ] * (0.915%]) * [9.27E-7 tonne/GJ]

Notes:
Losses from pipeline material, installation, engineering, and administration included with production.
GJ = Giga-Joules
tCO2e = tonnes Carbon Dioxide Equivalent

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3. Tannehill, C., et. al., (March 13-15, 1995) *U.S. Gas Conditioning and Processing Plant Survey Results* . Proceedings of the 74th Annual GPA Convention. San Antonio, TX.
4. Tannehill, C., et. al., (March 16-18, 1992*) Can You Afford to Extract Your Natural Gas Liquids?* . Proceedings of the 71st Annual GPA Convention. Anaheim, California.
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Gas Turbine Lifecycle Summary Calculations
Natural Gas Transmission

Net Energy Analysis

Losses from Transmission = Fuel Losses + Pipeline, compressor station, & misc. losses + Pipeline operation & maintenance losses

Transmission Fuel Loss = Fuel Delivered to 620 MW Plant * Pipeline Fuel Loss[1]
[34,054,556 GJ] = [1,222,020,000 GJ] * [2.79%]

Transmission Pipeline Material Embodied Energy Loss = Transmission Pipeline Embodied Energy[2,3] * Plant fraction of US Nat Gas[1] / Pipeline lifetime * Plant Lifetime
[1,066,847 GJ] = [1,109,340,032 GJ] * [0.192%] / [80 yrs] * [40 yrs]

Transmission Pipeline Installation Energy Loss = Transmission Pipeline Labor Energy[2,4,5] * Plant fraction of US Nat Gas[1] / Pipeline lifetime * Plant Lifetime
[582,546 GJ] = [605,749,193 GJ] * [0.192%] / [80 ys] * [40 yrs]

Transmission Pipeline Engineering & Admin Energy Loss = Transmission Pipeline E&A Energy[2,4,5] * Plant fraction of US Nat Gas[1] / Pipeline lifetime * Plant Lifetime
[545,840 GJ] = [567,580,741 GJ] * [0.192%] / [80 yrs] * [40 yrs]

Compressor Station Losses = Energy Requirements for Material, Engineering & Installation[5,6] / Equipment Lifetime * Fraction applicable to plant[7] * Plant Lifetime
[123,333 GJ] = [110,681,344 GJ] / [40 yrs] * [0.11%] * [40yrs]

Misc. Equipment Losses = Energy Requirements for Material, Engineering & Installation[5,6] / Equipment Lifetime * Fraction applicable to plant[7] * Plant Lifetime
[33,460 GJ] = [30,027,696 GJ] / [40 yrs] * [0.11%] * [40yrs]

Pipeline Operation & Maintenance Losses = U.S. Annual Energy Requirements[5,6] * Fraction applicable to plant[7] * Plant Lifetime
[440,839 GJ] = [9,890,454 GJ/yr] * [0.11%] * [40 yrs]

Natural Gas Transmission (Continued)

Greenhouse Gas Emissions

Transmission Emissions = Fuel Related Emissions + Pipeline, compressor station, & misc. emissions + operation & maintenance emissions
[4,658,827 tCO2e] = [4,460,037 tCO2e] + [167,877 tCO2e] + [30,913 tCO2e]

where:
Fuel Related Emissions = CO2 emission + CH4 emission + N2O emission
[4,460,037 tCO2e] = [1,353,054 tCO2e] + [3,098,683 tCO2e] + [8,300 tCO2e]

CO2 emission = Transmission Fuel Loss * (1 - fraction methane leaks[1,6]) * Emission Factor for NG Combustion[7]
[1,353,054 tCO2e] = [34,054,556 GJ] * [0.848] * [0.0469 tonne/GJ]

CH4 emission = Global Warming Potential[8] * U.S. Transmission CH4 Emissions[6] * Plant % of US Nat Gas Deliveries[1] * Plant Lifetime
[3,098,683 tCO2e] = [21] * [2,200,000 tonnes] * [0.168%] * [40 calendar years]

N2O emission = Global Warming Potential[8] * Transmission Fuel Loss * (1 - fraction methane leaks[1,6]) * Emission Factor for NG Combustion[7]
[8,300 tCO2e] = [310] * [34,054,556 GJ] * [0.848] * [9.27E-7 tonne/GJ]

Pipeline, compressor station, & misc. emissions - Example shows pipeline material only
Pipeline Material Emissions = Transmission Pipeline Material Embodied Energy Loss * I/O Pipe Emission Factor[5]
[78,410 tCO2e] = [1,066,847 GJ] * [0.0735 tonneCO2-equiv / GJ]

Pipeline Operation & Maintenance Emissions = U.S. Annual Transmission O&M Emissions[5,6] * Fraction applicable to plant[7] * Plant Lifetime
[30,913 tCO2e] = [693,542 tCO2e/yr] * [0.11%] * [40 yrs]

Notes:
GJ = Giga-Joules
tCO2e = tonnes Carbon Dioxide Equivalent

References:

1. Energy Information Administration (October 1999). *Natural Gas Annual 1998* . (DOE/EIA-0131(98)).
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Gas Turbine Lifecycle Summary Calculations
Plant Construction and Operation

Net Energy Analysis

Plant Building Materials
Material Embodied Energy = Summation of: {Mass of Material[1] X * Embodied Energy Factor[2] for Material X}
example given: Concrete. See text Table 3 for listing of plant material masses and energy factors.
[40,876 GJ] = [29,660 tonnes] * [1.4 GJ/tonne]

Plant Equipment
Plant Equipment Energy = Summation of: {Plant Equipment Cost[1] X * I/O Energy Factor[3] for Equipment X}
example given: pumps
[38,067 GJ] = [$3,820,757] * [0.009963 GJ/$]

Construction Labor
Construction Energy = Summation of: {Construction Cost[1] X * I/O Energy Factor[3] for Item X}
example given: site assessment & permitting
[772 GJ] = [$327,000] * [0.002362 GJ/$]

Plant Operation and Maintenance
O&M Energy = Summation of: {Annual O&M Cost[1] X * I/O Energy Factor[3] for Item X} * Plant Lifetime * Capacity Scaling[4]
example given: routine maintenance
[185,687 GJ] = [$500,000/year] * [0.006809 GJ/$] * [40 years] * [75%/55%]

Plant Construction and Operation (Continued)

Greenhouse Gas Emissions

Plant Building Materials
Material Emissions = Summation of: {Mass of Material[1] X * Emission Factor[2] for Material X}
example given: Concrete.
[15,419 tCO2e] = [29,660 tonnes concrete] * [0.5199 tCO2e/tonne concrete]

Plant Equipment
Plant Equipment Emissions = Summation of: {Plant Equipment Energy for Item X * I/O Emission Factor[3] for Equipment X}
example given: pumps
[2,715 tCO2e] = [38,067 GJ] * [0.0713 tCO2e/GJ]

Construction Labor
Construction Emissions = Summation of: {Construction Energy for Item X * I/O Energy Factor[3] for Item X}
example given: site assessment & permitting
[53 tCO2e] = [772 GJ] * [0.06925 tCO2e/GJ]

Fuel Consumption
Plant CO2 Emissions = Lifetime Fuel Consumption * Emission Factor for NG Combustion[5]
[61,801,403 tCO2] = [1,222,020,000 GJ] * [.05057 tCO2/GJ]

Plant CH4 Emissions = Global Warming Potential[6] * Lifetime Fuel Consumption * Emission Factor for NG Combustion[5]
[24,875 tCO2e] = [21]*[1,222,020,000 GJ] * [.0000010 tCO2e/GJ]

Plant NO2 Emissions = Global Warming Potential[6] * Lifetime Fuel Consumption * Emission Factor for NG Combustion[5]
[351,238 tCO2e] = [310]*[1,222,020,000 GJ] * [.0000009 tCO2e/GJ]

Plant Operation and Maintenance
O&M Emissions = Summation of: {Energy Required for O&M Item X * I/O Emission Factor[3] for Item X}
example given: routine maintenance
[13,140 tCO2e] = [185,687 GJ] * [0.07076 tCO2e/GJ]

Notes:
GJ = Giga-Joules
tCO2e = tonnes Carbon Dioxide Equivalent

References:
1. Based on data from Sherman M. (2000) Vice President, Project Development., Aquila Energy, and from Morford K. (2000) Black & Veatch Corporation.
2. Reference for material embodied energy and emission factors included in Appendix B.
3. Green Design Initiative, Carnegie Mellon University, via http://www.eicola.net/.
4. Capacity scaling accounts for difference between assumed capacity (75%) and Aquila[1] budgeted capactiy (55%).
5. U.S. Environmental Protection Agency (April 1999). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 1997. (USEPA #236-R-99-003).
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Gas Turbine Lifecycle Summary Calculations
Decommissioning and Land Reclamation

Net Energy Analysis

Equipment Decommission Energy = Estimated Equipment Decomissison Cost[1] * I/O Energy Intensity[2]
[41,972 GJ] = [$6,034,821] * [0.006955 GJ/$]

Building Decommissioning Energy = Building Volume[3] * Demolition Cost[4] * I/O Energy Intensity[2]
[744 GJ] = [382,200 cf] * [$0.28/cf] * [0.006955 GJ/$]

Land Reclamation Energy = Acreage[5] * Seeding Cost[4] * I/O Energy Intensity[2]
[16,507 GJ] = [701 acres] * [$1500/acre] * [0.01569 GJ/$]

Greenhouse Gas Emissions

Decommission Emissions = Decomissison Energy * I/O Emission Factor[2]
[3,023 tCO2e] = [42,714 GJ] * [0.07076 tCO2e / GJ]

Land Reclamation Emissions = Land Reclamation Energy * I/O Emission Factor[2]
[937 tCO2e] = [16,507 GJ] * [0.05677 tCO2e / GJ]

Notes:
GJ = Giga-Joules
tCO2e = tonnes Carbon Dioxide Equivalent

References:

1. Estimated as 10% of construction cost.
2. Green Design Initiative, Carnegie Mellon University, via http://www.eicola.net/.
3. Reference for material embodied energy and emission factors included in Appendix B.
4. Frank R. Walker Company. (1999) *The Building Estimator's Reference Book.* (26th ed.) Chicago, Il.
5. Estimate includes plant site, and a fraction of U.S. land utilized for gas production and transmission.

Appendix B: Material Embodied Energy and Emissions

Element or Alloy	Material Embodied Energy* GJ/Tonne	ref.	Material Embodied Emissions* kg CO_2/tonne	Reference
Chromium	82.9	[B1]	5,393	[B5]
Concrete	1.4	[B2]	520	[B5]
Copper	131	[B2]	7,446	[B5]
Iron	23.5	[B2]	1,688	[B5]
Carbon Steel	34.4	[B2]	2,471	[B5]
High Alloyed Steels	53.1	[B4]	3,275	[B5]
Manganese	51.5	[B3]	5,502	[B5]
Molybdenum (FeMo)	378.0	[B1]	9,410	[B5]
Plastic	54.0	[B5]	6,388	[B5]
Silicon	158.6	[B3]	159	[B5]
Vanadium (FeV)	3,711.2	[B1]	228,379	[B5]

*Data compiled or calculated by Scott White (1999), University of Wisconsin.

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